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and Technology
Projects

GEOTHERMAL ENERGY RESOURCES IN BRITISH COLUMBIA

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Energy, Mines and
Petroleum Resources

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GEOTHERMAL ENERGY RESOURCES IN BRITISH COLUMBIA

A study of factors affecting development and utilization

Prepared for

Ministry of Energy, Mines and Petroleum Resources

of the Province of British Columbia

by

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October 30, 1981

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1.0 INTRODUCTION AND TERMINOLOGY

1.0 INTRODUCTION AND TERMINOLOGY

1.1. Definition and Historical Outline

"Geothermal energy" is heat generated and stored within the earth. A portion of this heat can be tapped and utilized--either directly or after conversion to electricity. At the present time only a small fraction of the world's available geothermal energy is being utilized for human endeavors.

The "geothermal gradient" is the increase in the temperature of the earth's crust relative to depth. Although the geothermal gradient varies from place to place, the generally accepted average value for measurements taken on continents is about 25-30°C per kilometer of depth.

Evidence for high subterranean temperatures was first manifested to mankind by hot springs and volcanic eruptions. As human society and science progressed, additional evidence was gathered and quantified from deep metal mines, coal mines, oil and gas wells, and in recent years, oceanographic studies. Patterns and regularities were established and systematic variations in the subsurface thermal regime were measured. Certain positive variations lend themselves to development for the service of human energy needs.

It is estimated that the temperature of the earth increases to 4 800°C at the inner core. Scientific evidence suggests that the high temperature in the interior of the earth is a result of heat generated during the formation of the earth, and which continues to be generated at present by decay of radioactive elements. Heat flows from the interior of the earth through its crust and eventually into the oceans and atmosphere. For a given area this flow of energy is quite small in comparison to amounts used in human endeavors. For example, in most continental areas about 60 milliwatts of thermal energy flows through each square meter. However, the amount flowing out through the entire earth's crust is enormous, about 35 000 000 MW (PIC, 1979). Likewise, the quantity of heat stored in the upper part of the earth's crust is enormous. Diment et al (1975) estimated that about 33 x 10^{15} gigajoules are stored in the upper 10 km of the crust in the United States. Canada has a slightly larger area, so a comparable value might be 35 x 10^{15} gigajoules (or 11 000 000 gigawatt-centuries).

Very little of this heat is directly useful. Utilization of geothermal energy is concerned with identifying and exploiting those small pockets of high temperature rock, water, or brine which are natural concentrations of heat at an accessible drilling distance from the surface. Such deposits owe their existence to the geology of the earth's crust and they tend to occur in volcanic areas, in deeply faulted areas, and in thick and extensive sedimentary basins.

Geothermal energy has been utilized by man since prehistoric times. The first historic records are of utilization for health, therapy, and recreation in bathing spas, such as the early Roman baths at Bath, England. In the 19th century geothermal energy was used at the place now known as Larderello, Italy, for the purpose of running evaporators to extract and concentrate boric acid. It was at the same site in Italy, in 1904, that the first geothermal-powered electric generating station was constructed.

Iceland is the pioneer in use of geothermal energy for space heating. The first development was in the 13th century. Subsequently, and largely in the current century, a central collection and distribution system was set up in Reykjavik and now approximately 110 000 people are served by geothermal heating in their residences and businesses.

At the present time 11 countries have installed electrical generating capacities which total 1 800 megawatts and ten countries have installed direct use systems currently serving thermal demands at the rate of about 7 000 megawatts (thermal), or about 25 billion Btu's per hour.

1.2 Abbreviated Terms of Reference

The terms of reference for this study are contained in correspondence between the Ministry of Energy, Mines and Petroleum Resources and Nevin Sadlier-Brown Goodbrand Ltd. (NSBG) dated September and October, 1978. NSBG were to be the principal authors and were to obtain advice from economists, engineers and experts in natural resource law. Authority to conduct this study was received in December, 1979 and the study has progressed according to the following general terms:

> This study is concerned with the geothermal resources of the Cordillera, which includes most of B.C. and stretches into the southern Yukon and western Alberta, and the north eastern sedimentary basins.
>
> The resource may be one of several types: dry steam, wet steam, superheated water, hot water, warm water or hot dry rock.
>
> The utilization of the resource includes electrical generation, space heating, water heating, and process heat (industrial and agricultural).
>
> The purpose of the study is to evaluate the market penetration of geothermal energy into the energy resource market of B.C. over 25 years. This requires an estimate of the location and properties of the resource available, an analysis of supply and demand compatibility, and an economic comparison with conventional energy resources. Geothermal resources external to B.C. are mainly of interest if located near to residential areas or an electrical grid within B.C.

As work progressed communication between the client and consultant refined certain aspects of the terms of reference.

1.3. Background in Science

The study and the development of geothermal energy draws on the earth sciences, physics, chemistry, and engineering. It is impossible to discuss geothermal energy without the use of technical language, or without the rigour and precision which are part of scientific and engineering practice. We have attempted to explain technical language throughout, and in particular in Appendices A and B.

The development of geothermal energy has accelerated rapidly over the last decade, reaching an estimated rate of growth at present of about 19% per year worldwide (Muffler and Guffanti, 1979). It is fortunate for us that this rapid development of new concepts and new engineering techniques is taking place in a technological age. In other words, geothermal development is not thrusting into the unknown, as were comparable endeavors during the industrial revolution; it has the ability to draw from (and to contribute to) highly developed geological and geophysical arts, advanced drilling and completion technology, sophisticated electrical systems engineering, space-age materials and metallurgy, and the latest in computer technology.

Geology. Foremost, geothermal resources are mineral resources. This theme will recur throughout this study. Geothermal resources share many broad characteristics with other materials extracted from the earth's crust such as oil, gas, metals, coal, and industrial minerals. The distribution and locations of geothermal resources are determined by geological phenomena. The identification and discovery of geothermal resources depends upon geological thinking and craftsmanship. The development and withdrawal of geothermal resources depends upon geophysical and drilling technology.

Geologic terms are reviewed in Appendix B; geology and exploration methods are outlined in Appendices C and D.

Physics and Engineering. Accurate treatment of geothermal energy utilization requires a familiarity with the concepts of energy, power, specific heat and temperature.

"Energy" in physical terms equates with work and heat. A quantity of energy is distinct and limited, and described in familiar mechanical thermal or electrical units: viz. horsepower-hours, foot-pounds, newton-metres; British thermal units (Btu), calories, joules; or kilowatt-hours.

"Power" is energy per unit of time, or the ongoing capacity to sustain work over a period of time, and some counterpart units to energy are: (1) mechanical--horsepower, newton-meters per second; (2) thermal--

Btu's per hour, joules per hour; (3) electrical--kilowatts.

"Specific heat", "heat content" or "enthalpy" is the quantity of heat (thermal energy) contained in a given amount of a substance, and it depends upon the temperature, pressure and state of the substance. For each simple solid or liquid, enthalpy has a simple one-to-one relationship with temperature. Increasing the temperature increases the enthalpy; decreasing the temperature decreases the enthalpy. Similarly, adding heat increases the temperature of the substance while withdrawing heat decreases its temperature.

When the substance under consideration is a gas, such as steam, or is a mixture of liquid and gaseous states, the enthalpy is generally increased by compressing the substance (doing "work" upon it) and the enthalpy is decreased by allowing the substance to expand against a load (or to do work). This is the basis for using steam to drive turbines and generate electric power. In a gas, such as steam, the temperature, pressure, volume, and enthalpy are all interrelated.

Units of Measurement. We have attempted to use SI units in most of this report, with the following exceptions:

1. Temperature--we use degrees Celsius, not Kelvin;

2. Power, in direct-use operations--the geothermal industry elsewhere prefers "kilowatts thermal" (kWt) to "kilojoules per hour"(kJ/h); we use both;

3. Tubular goods--diameters of drill bits, pipe, and casing are measured in inches worldwide; we use such dimensions and repeat them in millimeters.

Because many Canadians do not have instant appreciation of values given in metric units, we add standard English units to some descriptions and tables. Fluid flows from wells are a good example. We use the familiar gallons per minute (gpm) as well as liters per second (L/s).

Various conversion tables are given in Appendix A.

1.4. Institutional Factors

As mentioned previously, geothermal energy has the benefit of developing during an age of rapid and widespread exchange of technical information. Moreover, it is developing under the auspices of a highly complex society. Although differing from place to place, the social fabric generally poses such questions as resource ownership, taxation of industrial operations, responsibilities toward the community, varying degrees of national or provincial planning with regard to industrial development and energy balance, and transportation of energy across international or interprovincial boundaries.

Industrial or energy-supply developments are studied from a cost-benefit standpoint if they are undertaken by an entity in the public sector of the economy, and they are compared rigourously to any and all alternative developments. If such developments are undertaken by the private sector they are examined in the same light, but the criteria for development include risk, payback period, and return on investment. In each case large projects require substantial financing, some of which has to be obtained externally.

In the case of this study it is not enough to examine only the geological, physical and engineering aspects of geothermal energy. We perceive the development of the commodity in British Columbia to depend more upon the nature and future actions of the institutions which exist in British Columbia and in Canada and which can, by their action or inaction, influence the rate of development of geothermal resources.

Geothermal resources, as mentioned, are energy resources of a mineral nature. Exploration must precede development; development and concomitant capital outlays must precede any benefits. At present, the future Canadian production and trade in coal, oil and gas--all mineral and all energy in nature--are the subject of considerable thought and debate.

In our discussion of the rate of penetration of geothermal resources (Sections 7.0 and 8.0; and Appendix I), we have considered these topics. We have also considered the long and rich Canadian heritage of mineral resource expertise, and the willingness of Canadian institutions to conduct exploration and development.

1.5. Responsibility

Nevin Sadlier-Brown Goodbrand Ltd. (NSBG) were responsible for research and for writing the geological aspects and notes on various geothermal developments. The principal contributors to these sections are Andrew E. Nevin, P.Eng., Brian D. Fairbank, P.Eng., and D.J. Brownlee. NSBG also edited and incorporated the work of all contributors, and has final responsibility for the study. NSBG are consulting geologists and engineers active in geothermal work since 1972.

Canadian Resourcecon Ltd., economists who specialize in energy sources and distribution, were responsible for the economic analyses. Principal authors are Douglas Strang (system electric) and Willy Zittlau (local electric and space heating). They were assisted by D.W. Thomson and Associates, engineers with special skills in heating technology. Donald Strang provided figures and calculations for space heating models.

Appendix I discusses alternative institutional factors to those which exist at present. The conditions for entry of the private sector into geothermal resource exploration and development were drafted by two solicitors, each of whom has expertise in mineral and energy resource law, Brian E. Abraham and Graham H. Scott.

2.0 WORLD STATUS OF DEVELOPMENT AND RESEARCH

2.0 WORLD STATUS OF DEVELOPMENT AND RESEARCH

2.1. Distribution of Geothermal Resources

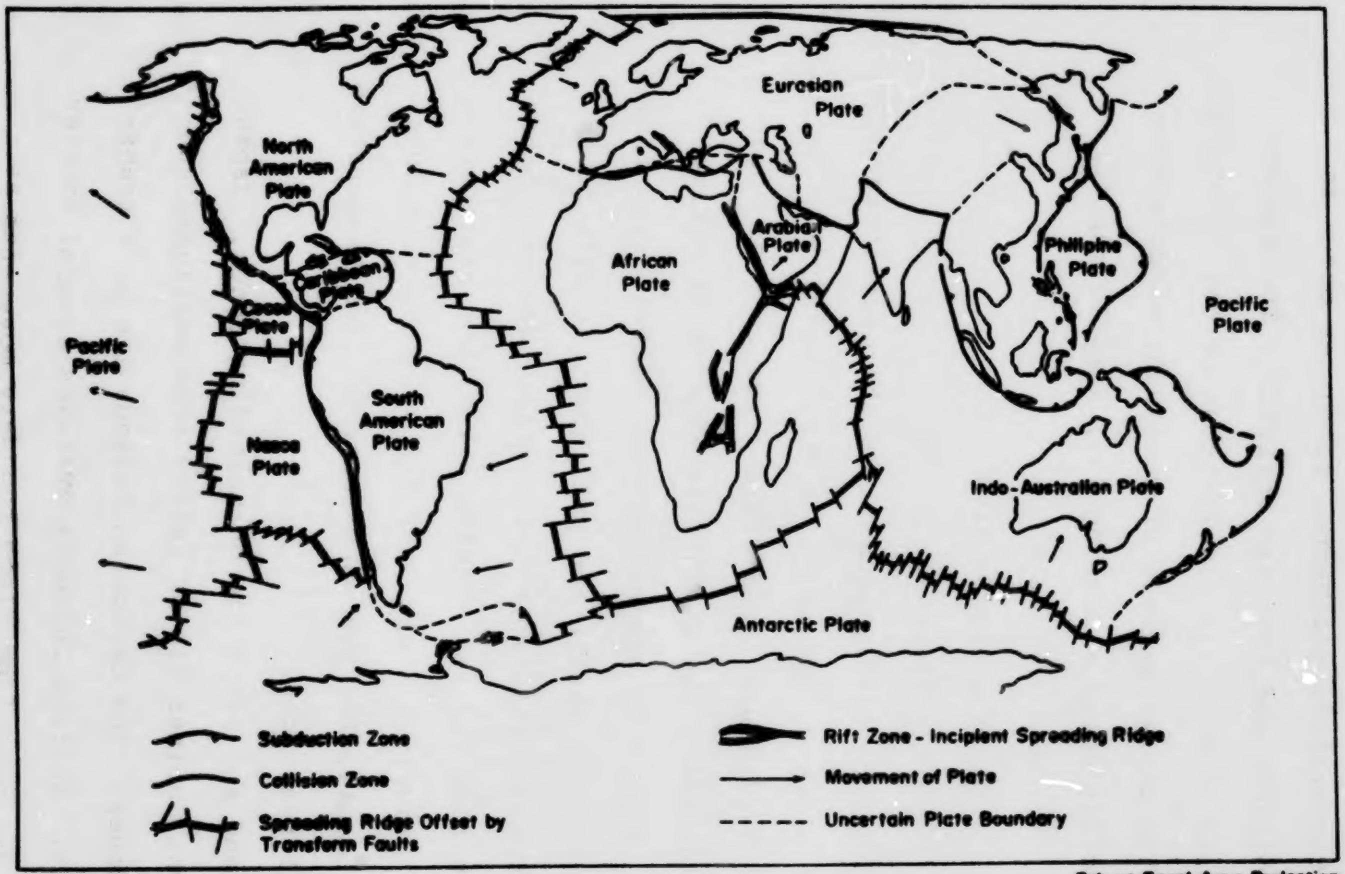
High temperature geothermal resources occur in zones of volcanic and tectonic activity. The circum-Pacific "Ring of Fire" is a well-known phrase denoting the volcanism characteristic of continent margins facing the Pacific Ocean. Drawing 2-1, a world map reproduced from Derry (1980), summarizes the distribution of crustal plates. The recently developed "plate tectonics" hypothesis satisfies a large body of observations, including the world distribution of active volcanos. Plates of oceanic or continental crust float on the underlying mantle and pull apart at rift zones, collide at subduction zones, and slide past each other along transform faults. Nearly all of the plate boundaries in Drawing 2-1 are loci for volcanic eruptions, and coincidently for the occurrence of high temperature geothermal resources.

- - - - - - - - - - - -

Drawing 2-1 follows

- - - - - - - - - - - -

Iceland and Kenya lie on spreading zones. Japan and the Philippines lie on island arcs overlying subduction zones. The Caribbean Islands lie on a transform fault. British Columbia overlies several complex features deriving from plate boundary movements as


North American Plate
Eurasian Plate
Pacific Plate
Caribbean Plate
Cocos Plate
Arabian Plate
African Plate
Philipine Plate
Pacific Plate
South American Plate
Nazca Plate
Indo-Australian Plate
Antarctic Plate
Subduction Zone
Collision Zone
Spreading Ridge Offset by Transform Faults
Rift Zone - Incipient Spreading Ridge
Movement of Plate
Uncertain Plate Boundary

Eckert Equal Area Projection

DRAWING 2-1

PLATES AND PLATE BOUNDARIES OF THE WORLD

Reproduced from D.R.Derry, World Atlas of Geology and Mineral Deposits, 1980; with permission of Mining Journal Books, London.

well. For a discussion of the relationship of these boundaries to volcanism in British Columbia, the reader is referred to Souther (1976). It is sufficient to note here that high temperature geothermal developments are installed in eleven countries and exploration or research is underway in about thirty more countries which lie on or near plate boundaries, or over anomalous "hot spots" in the upper mantle.

Lower temperature geothermal resources are likely to occur in many geological environments. The most readily accessible low temperature resources lie in the volcanic zones described above and in the vast sedimentary basins of continent interiors.

2.2. Electric Plants

The installed geothermal electric generating capacity is listed in Table 2-1 and summarized in Drawing 2-2. Total existing capacity is approximately 1 800 MW*. The United States has the largest installed

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Table 2-1 (four pages) follows

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Drawing 2-2 follows

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[*] As of the date of the draft of this report, November, 1980.

TABLE 2-1. Geothermal Power Units in Operation or in Planning (Continued)

Country/Plant Site	Year of installation	Capacity, MW
Azores		
São Miguel	1979	3.0
Chile		
El Tatio	Future	15.0
China		
Yang-pa-ching	1978	1.0
Costa Rica		
Miravalles	Future	40.0
El Salvador		
Ahuachapán:		
Auxiliary Unit	1975	1.1
Unit 1	1975	30.0
Unit 2	1976	30.0
Unit 3	1980	35.0
Berlín	Future	100.0
Chinameca	Future	100.0
Chipilapa	Future	50.0
San Vicente	Future	100.0
Guatemala		
Amatitlán	Future	50.0
Honduras		
Pavana or San Ignacio	Future	50.0
Iceland		
Námafjall (dismantled)	1969	3.0
Krafla:		
Unit 1	1978	30.0
Unit 2	Future	30.0
Svartsengi (Grindavik)	1978	2.0
Indonesia		
Kawah Kamojang	1979	0.25
Kawah Kamojang	Future	100.0
Italy		
Larderello 2 (5 units)	(*)	69.0
Larderello 3 (6 units)	1969	120.0
Gabbro	1969	15.0
Castelnuovo-V.C. (4 units)	(*)	50.0
Serrazzano (5 units)	(*)	47.0
Lago 2 (3 units)	(*)	33.5
Sasso Pisano (2 units)	(*)	15.7
Monterotondo	(*)	12.5
Sant'Ippolito-Vallonsordo	1972	0.9
Lagoni Rossi 1	1962	3.5
Lagoni Rossi 2	(*)	3.0
Sasso 1	(*)	7.0
Capriola	(*)	3.0
Molinetto	(*)	3.5
Travale	1973	15.0
Bagnore 1	1959	3.5
Bagnore 2	(*)	3.5
Piancastagnaio	1969	15.0
(unspecified sites)	Future	400.0
Japan		
Matsukawa	1966	20.0
Otake	1967	10.0
Onuma	1973	10.0

* Not available.

TABLE 2.1. Geothermal Power Units in Operation or in Planning (continued)

Country/Plant Site	Year of installation	Capacity, MW
Japan—Continued		
Onikobe	1975	25.0
Hatchobaru	1977	50.0
Kakkonda (Takinoue)	1978	50.0
Otake (pilot binary; dismantled)	1978	1.0
Mori (pilot binary; dismantled)	1978	1.0
Mori	1979	55.0
Kuzuneda	Future	50.0
Kenya		
Olkaria	Future	15.0
Mexico		
Cerro Prieto I:		
Unit 1	1973	37.5
Unit 2	1973	37.5
Unit 3	1979	37.5
Unit 4	1979	37.5
Unit 5	1982	30.0
Cerro Prieto II	Future	110.0
New Zealand		
Kawerau	1961	10.0
Wairakei, Station A:		
Machine 1 (IP)	1959	11.2
Machine 2 (HP)	1958	6.5
Machine 3 (HP)	1959	6.5
Machine 4 (IP)	1959	11.2
Machine 5 (HP)	1962	11.2
Machine 6 (HP)	1962	11.2
Machine 7 (LP)	1959	11.2
Machine 8 (LP)	1959	11.2
Machine 9 (LP)	1960	11.2
Machine 10 (LP)	1960	11.2
Wairakei, Station B:		
Machine 11 (MP)	1962	30.0
Machine 12 (MP)	1963	30.0
Machine 13 (MP)	1963	30.0
Ohaki (Broadlands):		
Unit 1	1983	50.0
Unit 2	1984	50.0
Unit 3	Future	50.0
Nicaragua		
Momotombo	Future	30.0
Panama		
Cerro Pando	Future	([a])
Philippines		
Tongonan (Leyte):		
Portable Unit	1977	3.0
Unit 1	1980	55.0
Unit 2	1981	55.0

[a] Not available.

TABLE 2.1. Geothermal Power Units in Operation or in Planning (continued)

Country/Plant Site	Year of installation	Capacity, MW
Philippines—Continued		
Makiling Banahaw (Los Baños):		
Wellhead Unit	1977	1.2
Unit 1	1979	55.0
Unit 2	1979	55.0
Unit 3	1981	55.0
Unit 4	1982	55.0
Tiwi:		
Unit 1	1979	55.0
Unit 2	1979	55.0
Unit 3	1981	55.0
Unit 4	1981	55.0
Southern Negros:		
Unit 1	1981	55.0
Unit 2	1982	55.0
Manat-Masara:		
Unit 1	1981	55.0
Unit 2	1982	55.0
All sites	Future	555.0
Turkey		
Kizildere:		
Wellhead Unit	1975	0.5
Unit 1	Future	14.0
U.S.S.R.		
Paratunka (dismantled)	1967	0.7
Pauzhetka	1967	5.0
Bolshoye-Bannoye	Future	8.0
All sites	Future	70.0
United States		
The Geysers:		
PG&E Unit 1	1960	11.0
PG&E Unit 2	1963	13.0
PG&E Unit 3	1967	27.0
PG&E Unit 4	1968	27.0
PG&E Unit 5	1971	53.0
PG&E Unit 6	1971	53.0
PG&E Unit 7	1972	53.0
PG&E Unit 8	1972	53.0
PG&E Unit 9	1973	53.0
PG&E Unit 10	1973	53.0
PG&E Unit 11	1975	106.0
PG&E Unit 12	1979	106.0
PG&E Unit 13	1980	135.0
PG&E Unit 14	1980	110.0
PG&E Unit 15	1979	55.0
PG&E Unit 16	1983	110.0
PG&E Unit 17	1982	110.0
PG&E Unit 18	1982	110.0

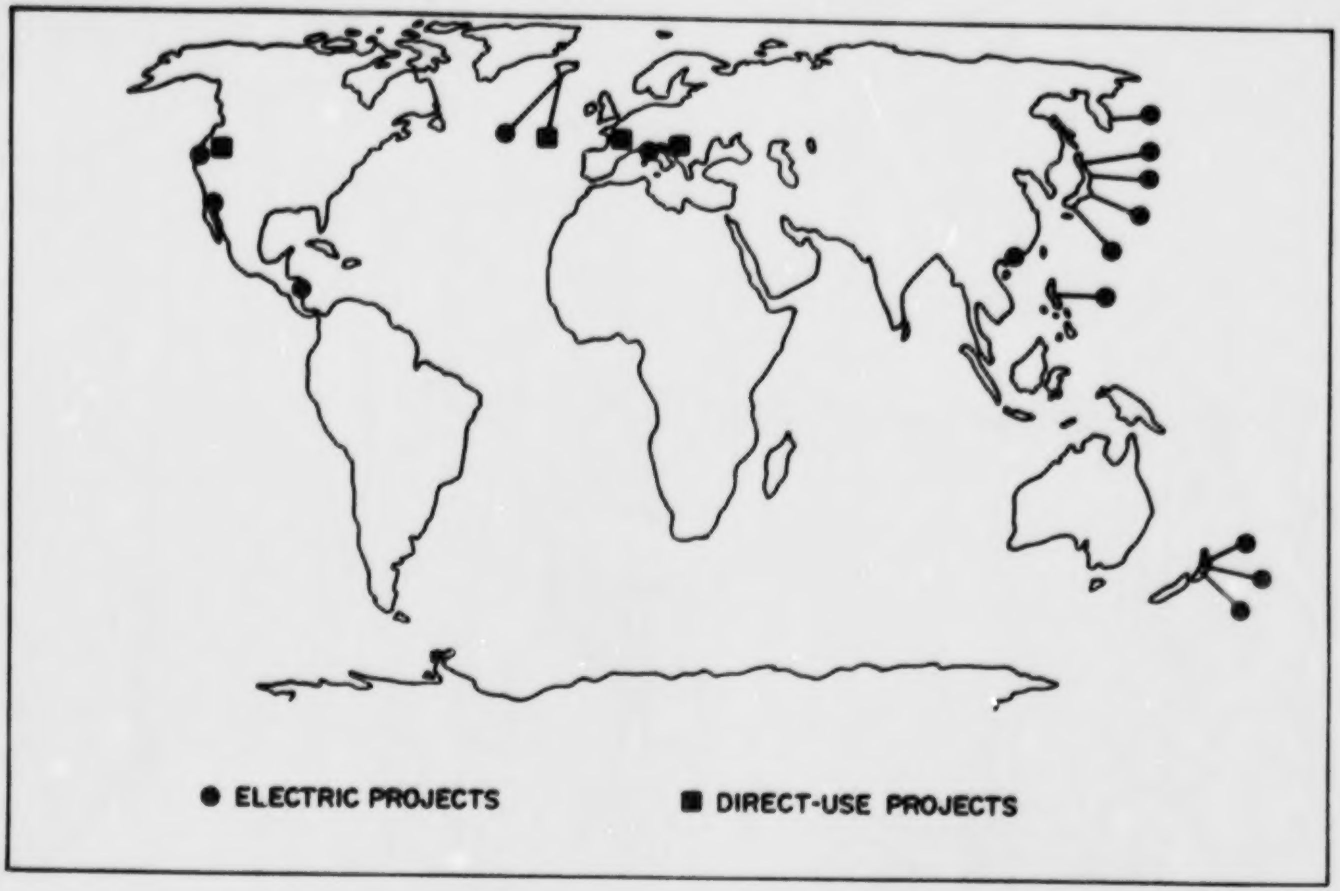
TABLE 2.1. Geothermal Power Units in Operation or in Planning (concluded)

Country/Plant Site	Year of installation	Capacity, MW
United States—Continued		
The Geysers—Continued		
PG&E Unit 19	Future	110.0
NCPA Unit 1	1981	110.0
East Mesa:		
Magmamax Dual Binary	1979	11.2
Republic Geothermal	1980	48.0
Brawley, So. Cal. Edison	1980	10.0
Puna, HGP Unit	1980	5.0
Raft River, Binary Unit	1980	3.35
Valles Caldera, Baca No. 1	1982	50.0
Salton Sea, SDG&E	1982	50.0
Heber:		
So. Cal. Edison	Future	45.0
SDG&E	Future	50.0
Westmorland	Future	50.0
Roosevelt Hot Springs	Future	52.0
Desert Peak	Future	20.0

Summary of actual, planned and projected geothermal power capacity in the world as of July 1979

	MW
(1) Total installed capacity	1758.9
(2) Planned or under construction	1720.8
(3) Future projections, near-term	2474.0
Total (1) + (2)	3589.7
Total (1) + (2) + (3)	5953.7

Reproduced directly from DiPippo (1980)


● ELECTRIC PROJECTS
■ DIRECT-USE PROJECTS

DRAWING 2-2

MAJOR INSTALLED GEOTHERMAL ENERGY PROJECTS capacity, all at the Geysers steam field in Northern California.

The types of geothermal systems driving these plants are reviewed in Appendix C. In Appendix F, some of the standard engineering variables concerned with converting geothermal energy to shaft or electric energy are discussed.

2.3. Direct Use Developments

The principal and historic developments using the heat from geothermal energy directly are listed in Table 2-2, and also summarized in Drawing 2-2.

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Table 2-2 follows

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Iceland is the leader with several local and district heating developments, the largest of which is at the capital city of Reykjavik. The U.S.S.R. and Hungary lead in the agricultural use of geothermal energy. Total use is approximately 7 000 MW(t) or about 25 000 kJ/hour.

One of the most widespread developments in the United States is at Klamath Falls, Oregon, where geothermal energy is used for residential, commercial and industrial heat.

The range of applications for direct use of heat spans every industrial or commercial activity where

TABLE 2.2. - Worldwide Direct Use of Geothermal Energy

Country	Space Heating/ Cooling (MW_t)	Agriculture/ Aquaculture (MW_t)	Industrial Processes (MW_t)
Iceland	680	40	50
New Zealand	50	10	150
Japan	10	30	5
USSR	120	5,100	---
Hungary	300	370	---
Italy	50	5	20
France	10	---	---
Others*	10	10	5
U.S.A.	75	5	5
TOTAL	1,305	5,570	235

* Kenya, Philippines

From Lienau (1980)

other sources of heat are used. Uses include the growing of fish, seedlings and crops, drying of agricultural products, canning, pasteurizing, drying of wood products, and extend toward high temperature use of process steam, such as production of methanol. This is more fully developed in Appendix G.

2.4. Resources versus Reserves

A simple device called a McKelvey diagram is reproduced from Muffler and Cataldi (1978) with reference to the geothermal resource base (Drawing 2-3). It pro-

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Drawing 2-3 follows

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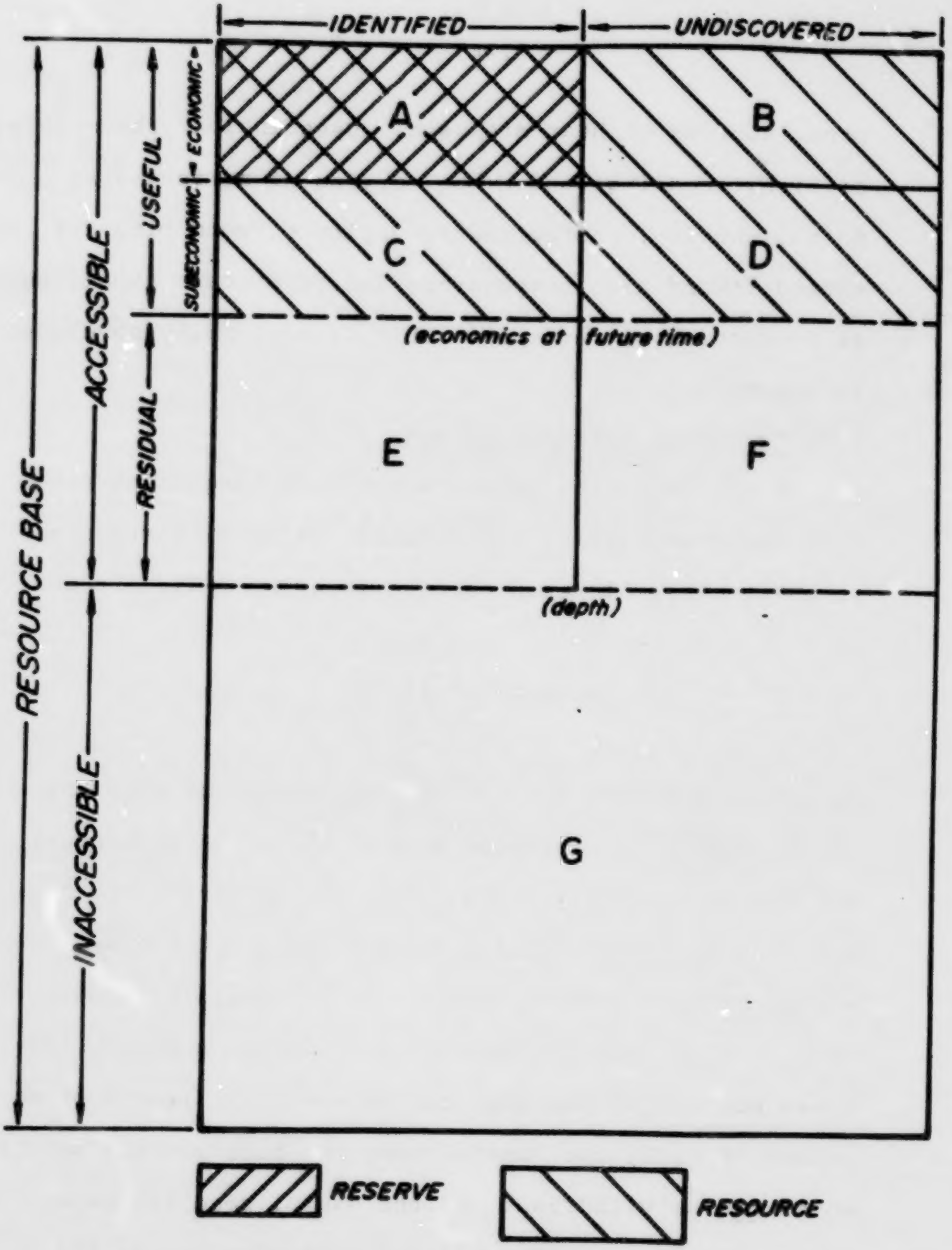
vides the means to resolve the difference between the large quantities of energy stored in the earth's crust and the small fraction available for utilization. "Resource base" refers to the entire quantity of thermal energy stored beneath a given area. The "accessible resource base" is that within reach of drilling technology. Because not all of the heat can be withdrawn from a given volume of rock, the "useful resource base" is the amount which can be withdrawn. Of the useful resource base, only a fraction can be utilized economically, so the "economic resource" is that part which can be extracted on a cost-competitive basis with other energy sources at a given time.


IDENTIFIED
UNDISCOVERED
RESOURCE BASE
ACCESSIBLE
INACCESSIBLE
USEFUL
RESIDUAL
ECONOMIC
SUBECONOMIC
A
B
C
D
(economics at future time)
E
F
(depth)
G
RESERVE
RESOURCE

DRAWING 2-3

McKELVEY DIAGRAM FOR GEOTHERMAL ENERGY, ILLUSTRATING "RESOURCE" vs "RESERVE"

(Muffler & Cataldi, 1978)

The diagram is partially divided by a vertical boundary which distinguishes between the "identified resource base" and the undiscovered part of the resource base. "Reserve" is only that part of the resource base which is both economic and identified, or area A of Drawing 2-3. As exploration is undertaken and proceeds, identified resources grow and the undiscovered fraction diminishes, thus areas A and C grow at the expense of areas B and D.

As new conversion technology is developed, additional resources become economic, and areas A and B grow downward into the field occupied by areas C and D.

If competitive sources of energy become more expensive in the future, areas A and B will move downward into C and D, which in turn will move downward into E and F. If drilling technology and cost cutting efforts are advanced, the entire upper part of the field, the accessible resource base, will grow at the expense of the inaccessible, and all of the field will move downward at the expense of area G.

The status of worldwide inventorying of geothermal resources at the present time is incomplete. The identified fraction of the accessible resource base is very small, and is presumed to be much smaller than the undiscovered fraction. In British Columbia, with the exception of the low energy projects which constitute the hot spring resorts, there is no identified fraction. With regard to high temperature resources, fields A, C and E do not yet exist.

Brook et al (1979) evaluated the energy believed to be contained in 215 identified hydrothermal convection systems in the United States. They conclude that wellhead thermal energy recoverable from the reservoirs might be approximately 400 x 10^9 kJ. Electricity extractable from the high temperature convective systems included within the sample is estimated to be approximately 23 000 MW for a 30-year period. They estimate, in keeping with the McKelvey diagram, that the identified component is approximately 1/5th of the total economically useful energy. Thus, if all high temperature deposits were discovered and proven, more than 3 000 000 MW-years could be generated.

In the same volume (Muffler, ed., 1979) various prospective energy figures are derived for all types of geothermal resources, and the reader is referred there for more information.

Our summary comment is that the widespread and systematic development of geothermal resources is in its infancy, and since development is going ahead on a project-by-project basis, the world inventorying of geothermal resources has only begun.

2.5. Momentum

Worldwide electrical growth is given by Drawing 2-4, after Muffler and Guffanti (1979). They observe

- - - - - - - - - - - -

Drawing 2-4 follows

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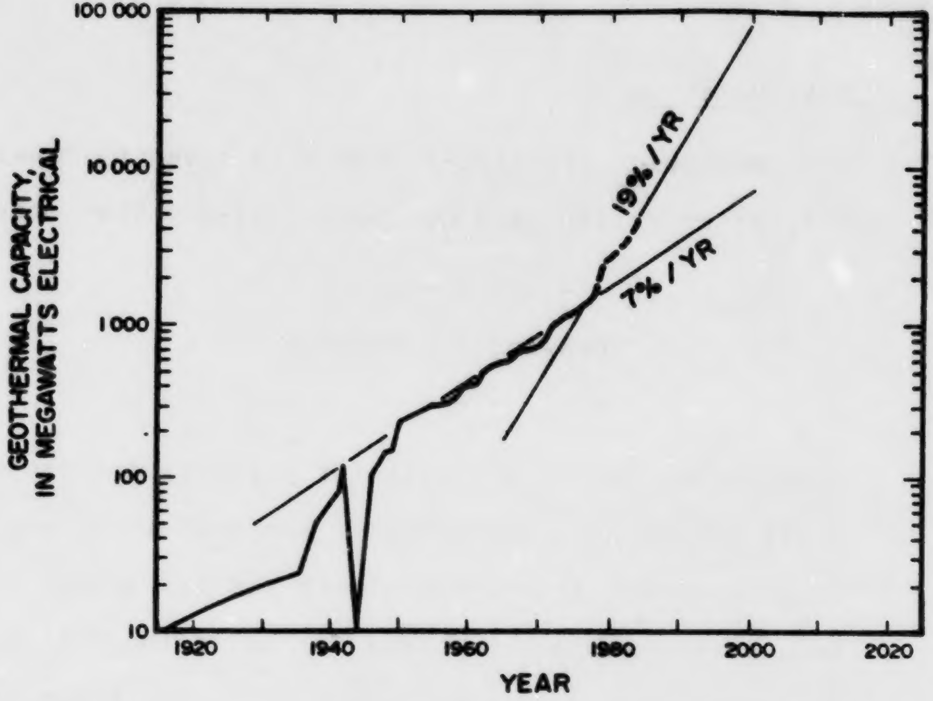
a 7% growth during the past forty years, and project a 19% growth into the future. Although it is generally dangerous to project growth too far ahead, there is a strong subjective basis for believing that this high rate will continue. Japan is adding plant capacity at a high rate, and in recent years has shown a keen interest in utilizing the services of foreign geologists and geophysicists to accelerate exploration. New entrants into geothermal development include the Philippines, Indonesia, Kenya, Iceland for electric generating, and the Central American countries. Mexico recently doubled the capacity of the Cerro Prieto plant.

In the United States there are probably more than 100 systematic exploration programs aimed at electrical



DRAWING 2-4

WORLDWIDE INSTALLED GEOTHERMAL ELECTRICAL CAPACITY AS A FUNCTION OF TIME

Dashed line indicates plants under construction or committed up to 1983.

Muffler & Guffanti, 1979

generating plants underway at the present time. Most of these are being conducted by the private sector, with strong financial support from the U.S. Department of Energy and generally with indirect support from various state agencies.

In addition to that leading element of research, site-specific exploration, which is treated in Appendices D and E, geothermal research is proceeding on several fronts. Research and development is concentrating on drilling tools and equipment able to withstand high temperatures, downhole logging materials capable of recording and transmitting information from high temperature environments, reliable mathematical modelling of two-phase (water and steam) flow in nonhomogeneous reservoirs, heat transfer models within geothermal reservoirs, and power plants utilizing two-phase flow or low temperature resources.

The literature regarding major and state-of-the-art advances in geothermal resources and development is growing rapidly. At the present time about 500 short technical papers are published in English annually, a dozen monographs are published annually by various institutions, and several dozen specific engineering studies are published each year by the private sector.

The Geothermal Resources Council, Davis, California, lists about 1 200 members. The organization was started as an outgrowth of a conference held in Oregon in 1971. The United Nations has sponsored three major meetings, and the U.S. Department of Energy sponsors several each year.

Several research organizations, industrial groups and nations specialize in various aspects of geothermal development. The turbine generators used in geothermal conversion are manufactured in Japan and in the United States. The scientific and engineering communities in Italy, Iceland, Mexico and New Zealand have each developed certain specialties.

The Los Alamos Scientific Laboratory, New Mexico, is the leader in hot dry rock technology. Lawrence Berkeley Laboratory concentrates on reservoir modelling. Battelle Laboratories Northwest, Richland, Washington, has produced several computer studies of cost and cost-benefit analysis. Idaho National Engineering Laboratory concentrates on utilization of moderate temperature resources, those at about 150°C. Sandia Laboratories in New Mexico is working on drilling methods and logging tools. Oregon Institute of Technology is the leader in North America for most aspects of direct-use technology.

3.0 GEOTHERMAL RESOURCES IN AND NEAR BRITISH COLUMBIA

3.0. GEOTHERMAL RESOURCES IN AND NEAR BRITISH COLUMBIA

3.1. Projects and Developments

3.1.1. Meager Creek Geothermal Project

In the early 1970s two geothermal investigations were started which have led to continuous work since at the Meager Creek area. In 1973 B.C. Hydro undertook a reconnaissance of the Lower Mainland and developed several targets, including Meager Creek. In early 1974 the federal Department of Energy, Mines and Resources (EMR) drilled two shallow wells at the Meager Creek hot springs.

B.C. Hydro's exploration is presently in an advanced stage of detailed prospect evaluation. EMR has continued with research in the area. Deep wells for steam discovery and testing are scheduled for 1981.*

Funding of the work has varied from year to year; for the past few years it has been jointly funded by B.C. Hydro and federal-provincial renewable energy funds.

Surveys conducted to date include geological mapping, various geophysical surveys, geochemical surveys, and sixteen shallow drill holes for temperature gradient and heat-flow surveys. (See Appendix D for discussion of methods.)

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*At the time of the final draft, October 1981, the first deep well was in progress at a depth of 2 600 meters.

Two thermal anomalies, with associated electrical resistivity anomalies, have been identified on opposite flanks of the Quaternary Meager Mountain Volcanic Complex. These are known as the South and North Reservoirs. A schematic drawing which shows the current state of knowledge of the Meager Creek geothermal system is reproduced as Drawing 3-1.

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Drawing 3-1 follows

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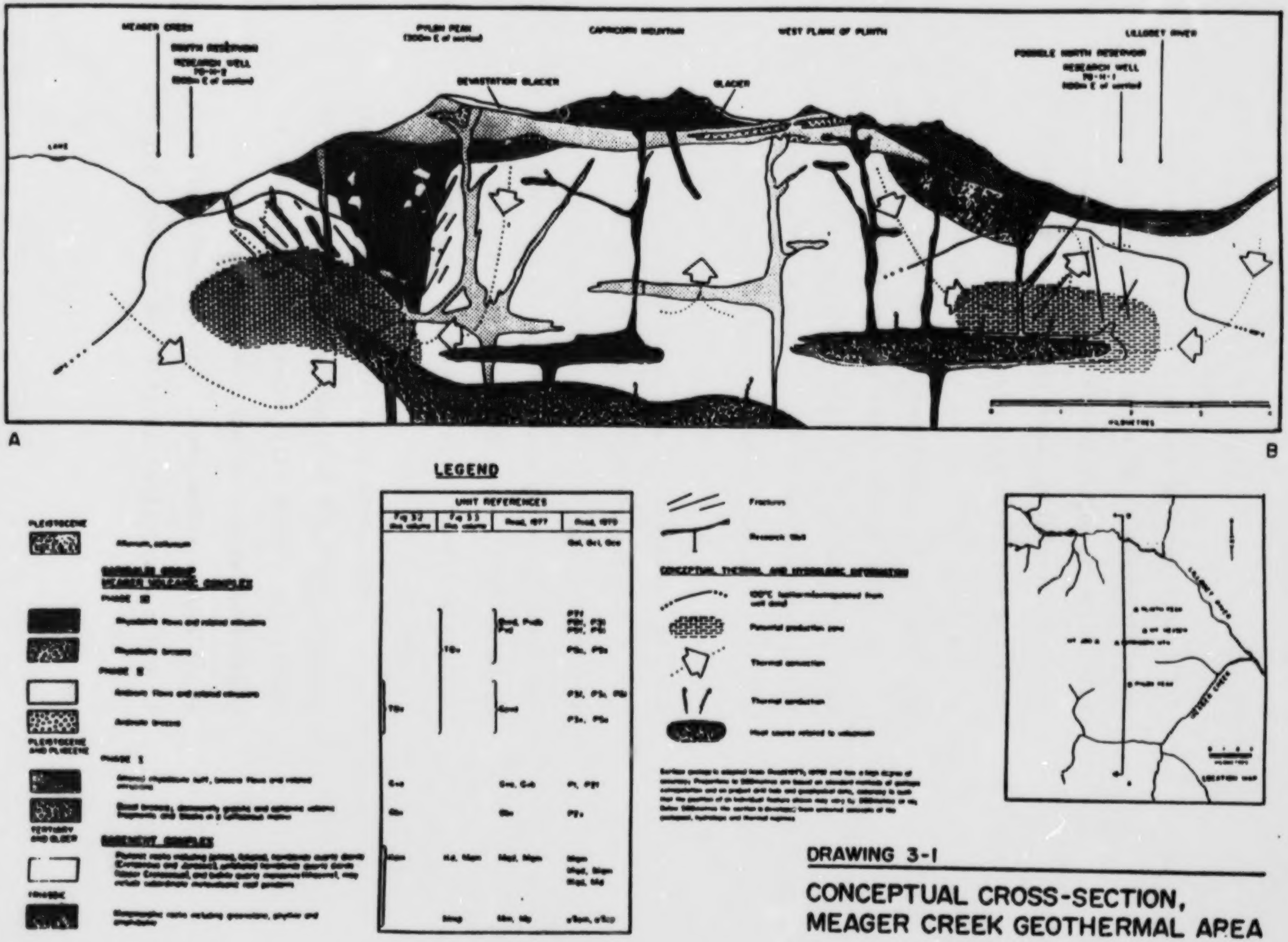
The South Reservoir resistivity anomaly in the Meager Creek valley extends laterally over an area 4 km by 1.5 km and is open to the north and south. Thirteen gradient holes have been drilled. With the main resistivity anomaly, gradients suggest that 300°C temperatures may exist at depths within 2 000-3 000 m of surface. The maximum temperature recorded was 202.2°C at a depth of 367 m.

The reservoir occupies open fractures and faults within otherwise impermeable quartz diorite. Quantitative porosity measurements of


MEAGER CREEK
SOUTH RESERVOIR
RESEARCH WELL
PYLON PEAK
CAPRICORN MOUNTAIN
WEST FLANK OF PLINTH
LILLOOET RIVER
POSSIBLE NORTH RESERVOIR
RESEARCH WELL
DEVASTATION GLACIER
GLACIER
LAKE
KILOMETRES
A
B
LEGEND
UNIT REFERENCES
PLEISTOCENE
Fractures
Research Well
Potential production zone
Thermal convection
Thermal conduction
LOCATION MAP

DRAWING 3-1

CONCEPTUAL CROSS-SECTION, MEAGER CREEK GEOTHERMAL AREA

(Fairbank, et.al., 1979, reproduced by permission of B.C. Hydro) drill-core samples indicate high porosity over some intervals of 20 m, particularly associated with faulting and volcanic dyke emplacement. Loss of circulation into the formation during drilling suggests that adequate permeability exists along fault zones for geothermal fluid production, if conditions persist with depth.

The Meager Creek hot springs are predominantly sodium chloride water, a product of mixed hydrothermal and cold waters. They are dilute (less than 5 000 ppm total dissolved solids), slightly acid or neutral, high in chloride, and moderately high in bicarbonate and sulfate. Semiquantitative spectographic analyses and mercury and fluoride analyses indicate that the thermal spring waters have low concentrations of heavy metal ions, borates, fluoride or constituents likely to cause engineering problems related to corrosion or toxicity.

The North Reservoir is in a preliminary stage of detailed prospect evaluation. A large Electrical resistivity anomaly, possibly due to geothermal water, is outlined over an area of eight square kilometers. One diamond drill hole to 603 m was drilled in 1978 and recorded 102.8°C temperature at 573.3 m with a bottom-hole gradient of 210°C/km. A coincidental relationship between zones of anomalous resistivity and hot geothermal water has not yet been established. A connection is inferred between the resistivity anomaly and the Pebble Creek hot springs, 5 km to the east.

Basement rock in the North Reservoir consists of fractured quartz monzonite and quartz-biotite-muscovite schist. Composition of the Pebble Creek hot spring is a dilute sodium bicarbonate brine. This, and several other criteria, suggest that the North and South Reservoirs are independent and separate systems, although derived from the same volcano.

3.1.2. Mt. Cayley Program

The Mt. Cayley area, between the Squamish and Cheakamus River valleys, 95 km north of Vancouver, was identified as a potential geothermal resource in a regional evaluation for B.C. Hydro (NSBG, 1974). Geological mapping of a preliminary nature and airborne infrared surveys were conducted during the course of initial work and further resistivity and drilling were recommended by the consultant. Subsequent work has been carried out by EMR. In the fall of 1977 two shallow holes were drilled in the Squamish Valley about 6 km west of Mt. Cayley by the Earth Physics Branch (Lewis, 1977). In 1979 the Geological Survey of Canada (GSC), carried out detailed mapping of the volcanics (Souther, 1980). Geophysical surveys and two diamond drill holes were conducted by the GSC in 1980.

Basement rocks, which a geothermal reservoir might occupy, are plutonic and metamorphic rocks of the Coast Crystalline Complex. Seven volvanic complexes have been mapped by Souther (1980) along the height of the land in the north-south belt 18 km long and up to 14 km in width. The volcanics are in the form of composite volcanos, domes and tuyas,and range in composition from basalt to rhyodacite. The bulk of volcanism is estimated to have occurred between 0.1 and 1.3 million years ago.

Two hot spring groups on the south slope of Mt. Cayley were discovered and sampled (Souther, 1980). The spring areas are about 2 km apart, at or near the border of volcanic intrusions, on the west side of the complex. Hot spring temperatures are between 18 and 40°C; geochemical data are not yet published.

The two drill holes are in the Squamish valley west of Mt. Cayley and about 5 km west of the springs. Both holes intersected pyritiferous metasediments and blocky diorite. Hole 304-1 was drilled to 213.4 m and encountered a low-volume artesian flow from diorite in the lower section which gradually approached 1 liter/second (L/s) at final depth. The gradient was 52.5°C/km. Hole 304-2, drilled to 243.8 m, made water also. Temperature gradient was calculated at 59.9°C/km for the lower 90 m (Lewis, 1977). Holes 304-1 and -2 reached maximum temperatures of 15.7 and 23.1°C, respectively. The temperature gradients are about double ordinary values.

Drill hole data and the style of volcanism indicate possible heat sources associated with high level subvolcanic intrusions.

3.1.3. Resorts

Facilities for bathing and recreation have been installed on eight hot springs in British Columbia. These are listed in Table 3-1. The

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Table 3-1 follows

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facilities range from the elaborate Harrison Hotel

TABLE 3-1 Hot Spring Developed for Recreation

Resort Area	Land Status	Thermal Springs	Developed Pools	Chemistry and Mineral Content	Recreational Facilities
Harrison 80 km east of Vancouver	private	2 springs (1 potash, 1 sulfur) at lakeshore protected by concrete wall; Average 63°C; 25 litres/second	1 public pool; 2 hotel pools (water piped 0.8 km) indoor 37°C, outdoor > 21°C	pH 8.5; potassium chloride; sodium, magnesium, and lime sulphate, bicarbonate of lime and iron, sulpherate hydrogen; 1033 total dissolved solids.	resort hotels open year round; boating, golfing curling, skating tennis, skiing, campgrounds.
Nakusp 3 km north of Nakusp, 100 km south of Revelstoke	Provincial Park	5 springs; Average 54°C; 1 litre/second	2 pools; 38°C, 44°C	sodium and calcium sulphate	built in 1973 b Nakusp with Pro incial funds; 7 motel rooms, campsite; expanding to increased accom dations, health tennis.
Ainsworth 50 km north of Nelson	private	issue from abandoned mineshafts; 45°C; 7 litres/second	1 outdoor pool; steam bath caves	pH 6.2; calcium bicarbonate potassium and lithium chloride, silica iron; 0.5% zinc; 1766 ppm total dissolved solids	Resort hotel op year round; boating.
Albert Canyon 37 km east of Revelstoke	private	26°C; 7 litres/second	2 pools; 26°C, 40°C (heated)	pH 7.5; low mineral content	campground seasonal.
Fairmont 112 km north of Cranbrook	private	9 spring vents; 35-49°C; 8 litres/second	3 outdoor pools; 35-42°C; 1 outdoor (lodge guests) 42°C	pH 6.8; calcium and magnesium bicarbonate, 400 ppm CO_2, radioactive; 2038 ppm total dissolved solids	resort lodge, motels, cottage open year round; trailer court, golfing, riding, boating, tennis, skiing.
Radium 145 km north of Cranbrook	Kootenay National Park	springs issue from prominent reddish stained fault zone; 35-45°C; 23 litres/second	2 outdoor pools; 27°C, 40°C	pH 7.3-7.8; sulphated calcium bicarbonate; strongly radioactive; 620 ppm total dissolved solids	resort hotels, motels and bung open year round; golfing, heli-s
Lakelse	private	9 springs; average temperature 85°C	1 indoor pool	pH 6.8-8.0; sodium sulphate type, relatively high content of lithium. 1100.6 ppm total dissolved solids	pool developed in 1968 as resort hotel (now close currently under study for develop ment.
Liard	Provincial Park	2 major vents, 40°C; 70 litres/second	1 pool for public bathing	sulfate dominated	pool, parking lot, walkway; moose frequent area.

to simple public pools such as Liard hot spring. Some resorts are destination types, such as Harrison, where the hot spring is a minor component of a much larger resort infrastructure. Other developments, such as Liard or Albert Canyon, cater to casual highway traffic.

It is our understanding that the Lakelse resort, now closed, is under study by TIDSA, a tourism agency jointly funded by the federal and provincial governments.

We further understand that one of the private owners of a hot spring facility augmented the temperature and flow of the hot water by drilling. Another owner intends to embark on such a program in the near future and to expand his facility accordingly.

Use of geothermal waters for bathing is historic and has an economic validity. The aspects of direct-use discussed subsequently in this report, however, are concerned with space heating and agricultural or industrial heat use.

3.1.4. Other Surveys

Two works specifically directed to cataloging thermal springs were published prior to economic conditions which drew attention to geothermal energy: Souther and Halstead (1973) and van Everdingen (1972).

In recent years two EMR surveys have attempted to systematically examine and measure the properties of thermal springs in British Columbia and the Yukon. The results of those surveys are presented by Souther (1976) and Crandall and Sadlier-Brown (1976). These and other data on thermal springs are summarized in Section 3.2. Goodbrand and Crandall (1977) conducted a literature search on behalf of the Department of Fisheries and Environment to study the potential use of thermal springs for fish culture in British Columbia.

Sproule and Associates Ltd. (1976) conducted a literature search on the potential for geothermal resources in the Prairie sedimentary basins. The study extended over several provinces, based on existing oil well data, and included northwestern British Columbia.

Reid Crowther and Partners Ltd. (1980) conducted an economic assessment of the extraction of geothermal brine from the sedimentary basins in the Fort Nelson and Dawson Creek areas. This report was commissioned by the Energy Conservation and Technology Division, Ministry of Energy, Mines and Petroleum Resources--the same client which has commissioned this report.

In 1978 EMR drilled two temperature-gradient and heat-flow measurement holes to depths of 425 m in a rock unit known as the Coryell Intrusive, located about 60 km north of Grand Forks, B.C. Temperature gradients measured are about 55°C/km (Lewis, 1979).

The studies listed above are starting points; however, none has identified or confirmed commercial geothermal resources.

3.2. Thermal Springs

A summary catalog of the known thermal springs in and near British Columbia is given in Table 3-2 of this report. The locations of these thermal springs are indexed by means of a serial number to Drawing 3-2. The serial number for each hot spring derives from the map number in the NTS map sheets which are universally used throughout British Columbia.

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Table 3-2 follows, 12 pages

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Drawing 3-2 follows

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The precision of the data varies widely. Some thermal springs are well studied; others are very little

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
82E-1	Snowshoe Rabbit	49 55 118 11	..	..	..	Alleged to occur beside Snowshoe Rabbit Lake	File
82E-2	Octopus Creek	49 44 118 00	49	small	..	H_2S discharge; 1 vent	McDonald (1978)
82E-3	Jordan Ranch	49 48 118 10	12	small	..	Flows into a 45 gallon drum	McDonald (1978)
82F-1	Ainsworth	49 44 116 54	45	7	40,000	1766 ppm total dissolved solids; pH 6.2; metamorphosed sedimentary and volcanic rock	Souther & Halstead (1973) McDonald (1978) Waring (1965)
82F-2	Crawford Bay	49 40 116 47	32	0.2	100	2 vents along Crawford Creek 2.5 km from Crawford Bay	McDonald (1978)
82F-3	Dewar Creek, St. Mary's River	49 55 116 28	82	..	..	Possible travertine deposit	McDonald (1978)
82F-4	Riondel	49 46 116 52	..	..	..	Old Bluebell mine workings	Bowman

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
82G-1	Wild Horse River	49 48 115 30	29	7	3000	pH 7.4; tufa deposit; 27 km east of Fort Steele	McDonald (1978)
82G-2	Fording Mountain	49 58 114 52	25	5	2000	70 ppm H_2S; 2655 ppm total dissolved solids pH 7.1; Rocky Mountain Formation, calcareous to arkosic sediments; 2 vents	Van Everdingen (1972)
82G-3	Mutton Creek	50 00 115 40		..	..	Alleged to occur 16 km east of Skookumchuk on the north side of Lussier River	File
82J-1	Lussier	50 08 115 35	43	4	2000	2207 ppm total dissolved solids; 50 ppm CO_2; pH 7.1; fractured Jubilee Formation; limestone; small log bathhouse and pool was built; 3 vents	McDonald (1978) Souther & Halstead (1973) Van Everdingen (1972)
82J-2	Ram Creek	50 02 115 35	35	3	1000	225 ppm total dissolved solids; pH 7.6; Jubilee Formation; dolomite; located downslope from surface expression of transverse fault	McDonald (1978) Souther & Halstead (1973) Van Everdingen (1972)
82J-3	Red Rock	50 13 115 42	..	..	..	Located 15 km up Kootenay River from Canal Flats; issues from river gravels overlying the Jubilee Formation	McDonald (1978) Souther & Halstead (1973)
82J-4	Fairmont	50 20 115 54	49	8	5000	2038 ppm total dissolved solids; 400 ppm CO_2; pH 6.8; fractured Jubilee Formation; commercialized with pools, golf courses, accomodations; 9 vents	McDonald (1978) Souther & Halstead (1973) VanEverdingen'72

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6joules/hr)	Comments on chemistry, geology, physical setting	Latest references
82K-1	Radium	50 38 116 02	43	23	10,000	630 ppm total dissolved solids; pH 7.3; Jubilee Formation; brecciated dolomite of the Redwall Fault; extensive commercialization of springs	McDonald (1978) Souther & Halstead (1973) Van Everdingen (1972)
82K-2	Halcyon	50 30 117 55	48	5	3000	pH 7.8; 3 vents; each enclosed in concrete	McDonald (1978)
82K-3	Nakusp	50 17 117 40	54	1	1000	4 vents; issue from talus; the town of Nakusp has built a pool	McDonald (1978)
82K-4	St. Leon	50 26 117 51	49	2	1000	pH 8.0; 1 vent issues from a calcite encrusted cave; 2 vents issue from fractures	McDonald (1978)
82K-5	Halfway River	50 28 117 51	55	3	2000	pH 7.5; flows from under rock bluff; 40 km up river another spring is supposed to occur	McDonald (1978)
82K-6	Wilson Lake	50 13 117 36	30	0.5	200	issues from a slide	McDonald (1978)
82K-7	Toby Creek	50 25 116 19	..	..	..	Alleged to occur 450 m up Delphine Creek from Toby Creek	Bowman

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
82K-8	Whiskey Point	50 42 117 49	..	..	..	Alleged to occur on Whiskey Point at north end of Upper Arrow Lake	File
82K-9	Fry Creek	50 05 116 45	..	..	..	Alleged to occur 3 km up Fry Creek	McDonald (1978)
82K-10	Mt. Baldur	50 22 118 00	..	..	..	Alleged to occur on the slopes of Mt. Baldur near Frosthall on the west side of Upper Arrow Lake	McDonald (1978) Bowman
82K-11	Frosthall	50 23 117 56	..	..	..	Alleged to occur on Frosthall Creek	Bowman
82K-12	Taylor	50 04 117 56	25	0.5	200	pH 8.5; spring flows from a 4 cm diameter diamond drill hole; located 8 km northwest of Burton, on the west side of Upper Arrow Lake	McDonald (1978)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
82N-1	Albert Canyon	51 08 117 45	26	7	2000	pH 7.5; located 2.5 km south of highway	McDonald (1978)
82O-1	Banff	51 10 115 35	34	55	20,000	950 ppm total dissolved solids; pH 7.5; The Banff Hotsprings are comprised of eight springs on Sulphur Mountain; they occur in sedimentary rocks in the Rocky Mountain thrust belt	Van Everdingen (1972)
83D-1	Canoe River	52 45 119 10	50	3	2000	Possibly drowned by McNaughton Lake	McDonald (1978)
83F-1	Miette	53 08 117 40	53	26	20,000	1146 ppm total dissolved solids, occurs in Jurassic Sedimentary rocks in the Rocky Mountain thrust belt	Souther & Halstead (1973)
92A-1	Mt. Baker	48 45 121 50	42	0.5	300	The spring occurs on the east side of Mt. Baker; in Miocene lavas overlying granite	Maring (1965)
92E-1	Ahousat, Flores Island	49 16 126 04	24.0	1.8	500	98 ppm total dissolved solids; pH 8.6; issuing from 1 vent in fractures; Mesozoic quartz diorite; situated 3 m above high tide mark	Goodbrand & Crandall (1977) Souther (1976)
92E-2	Sharp Point	49 21 126 16	50.5	7.5	5000	514 ppm total dissolved solids; pH 8.5; issuing from 1 vent in fractured Mesozoic quartz diorite. Situated on a rocky penn. on Pacific Ocean	Goodbrand & Crandall (1977) Souther (1976) Souther & Halstead (1973)
92F-1	Kennedy River	125 35 49 05	..	..	..	Alleged to occur on N bank about 2 km from tide water	Goodbrand & Crandall (1977)
92F-2	Pipestem	49 03 125 12	..	..	..	Alleged to occur on the north shore of the head of Pipestem Inlet	Wilson (1980)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
92G-1	Sloquet	49 45 122 20	64	100	100,000	760 ppm total dissolved solids; pH of 8.5; 4 vents issuing from overburden; underlain by coarse conglomerate; located in steep creek valley of Coast Mountains	Goodbrand & Crandall (1977) Souther & Halstead (1973)
92G-2	August Jacob's	49 48 122 16	49	-0.5	300	367 ppm total dissolved solids; issuing from 1 vent; metamorphosed sediments of the Coast Plutonic Complex; believed to have dried up	Goodbrand & Crandall (1977) Souther & Halstead (1973)
92G-3	Skookumchuk	49 59 122 28	54	40	30,000	1214 ppm total dissolved solids; pH of 8.5; issuing from 1 vent in overburden; underlain by metamorphics; situated on a river bench on the Lillooet River	Goodbrand & Crandall (1977) Souther (1976) Souther & Halstead (1973)
92G-4	Pitt River	49 44 122 43	57.3	0.5	400	951 ppm total dissolved solids; pH of 8.2; issuing from 1 vent in fractures; quartz diorite; situated 22 km up Pitt River from Pitt Lake	Goodbrand & Crandall (1977) Souther (1976) Souther & Halstead (1973)
92H-1	Harrison	49 20 121 46	63	250	200,000	1033 ppm total dissolved solids; pH 8.5; issuing from 2 vents; lower vent is sulphur dominated; upper vent potash dominated; metamorphosed sediments; developed as Harrison Hotels Resort	Goodbrand & Crandall (1979) Souther (1976) Souther & Halstead (1973)
92H-2	Clear Creek	49 41 121 45	43	50	30,000	340 ppm total dissolved solids; issuing from 3 vents; metamorphic rocks; situated on slope of valley in Coast Mountains; 9.5 km up Clear Creek	Goodbrand & Crandall (1979)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
92J-1	Meager Creek	50 34 123 30	59	500	400,000	2021 ppm total dissolved solids; NaCl dominant; pH 6.2; 4 vents issuing from fill; Meager Creek volcanic system; South Reservoir under geothermal exploration by B.C. Hydro and EMR since 1973; 10 drill holes, maximum depth 367 metres; maximum temperature 202°C; considerable geochemical and geophysical data	Fairbank et al (1980) Fairbank et al (1979) Read (1978) Hammerstrom & Brown (1977)
92J-2	Pebble Creek	50 34 123 30	60	100	80,000	1408 ppm total dissolved solids; $NaHCO_3$ dominant; pH 6.5; several vents issuing from fractures; Fall Creek monzonite stock, Meager Creek volcanic system; North Reservoir under geothermal exploration by B.C. Hydro and EMR since 1973; 1 drill hole 603 metres depth; thermal springs apparently several kilometres down drainage from reservoir; near inferred source of Bridge River ash, age about 2460 years	Fairbank et al (1980) Fairbank et al (1979) Read (1978) Hammerstrom & Brown (1977)
92J-3	Turbid Creek	50 06 123 17	30	..	..	3 vents issuing from contact zones of cupolas of Vulcan's Thumb dacite; tufa and sinter deposits	Souther (1980)
92J-4	Shovelnose Creek	50 05 123 16	30	..	..	2 vents issuing from granodiorite; tufa and sinter deposits	Souther (1980)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6joules/hr)	Comments on chemistry, geology, physical setting	Latest references
92K-1	Phillips Arm	50 30 124 22	..	..	..	Alleged to occur along the shore of Phillips Arm mid to north end	Goodbrand & Crandall (1979)
92L-1	Fair Harbour	50 04 127 05	..	..	..	Alleged to occur 2 km from head of Fair Harbour	Goodbrand & Crandall (1977) Souther & Halstead (1973)
92M-1	Sheemahant	51 47 126 35	..	..	..	Alleged to occur several km up the Sheemahant River from its mouth	Goodbrand & Crandall (1977)
92M-2	Washwash	51 52 126 40	..	..	..	Alleged to occur at or near the mouth of Washwash Creek	Goodbrand & Crandall (1977)
92M-3	Asseek	51 57 126 43	..	..	..	Alleged to occur at the mouth of the Asseek River	Goodbrand & Crandall (1977) Souther & Halstead (1973)

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Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
92N-1	Franklin	51 09 125 31	..	..	..	Alleged to occur on the east side of Franklin River 2 km below Franklin Glacier	McDonald (1977) Goodbrand & Crandall (1977)
92N-2	Canyon Lake,	51 17 125 37	..	..	..	Alleged to occur on the eastern shore of Canyon Lake (6th Lake)	McDonald (1977) Goodbrand & Crandall (1977)
92N-3	Pinter	51 18 125 37	..	..	..	Alleged to occur 2 km up Hoodoo Creek on the north side; one spring beside creek, one uphill from creek; pool was build at the upper spring	McDonald (1977) Goodbrand & Crandall (1977)
92N-4	Hoodoo	51 18 125 35	..	..	..	Alleged to occur 5 km up Hoodoo Creek on northside; situated in a canyon	McDonald (1977) Goodbrand & Crandall (1977)
920-1	Brigham	--	8	small	--	pH 6.3; tufa deposits; 2 vents; located at mile 38 of the Dog Creek road.	McDonald (1978)
920-2	Canoe Creek	--	--	--	--	Alleged to occur at the head of Canoe Creek 8 km from the BC Cattle Company ranch.	McDonald (1978)
920-3	Riske Creek	52 08 122 36	8	small	--	pH 6.3; tufa deposits; 1 vent	McDonald (1978)
92P-1	Williams Lake	51 58 121 50	12	small	..	pH 6.5; tufa deposit; large gas discharge	McDonald (1978)
93A-1	Clearwater	..	9	2	100	Located 17 km north of Wells Grey Park gates; tufa deposit	McDonald (1978)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
93D-1	Talheo	52 12 126 57	64	4.3	4000	628 ppm total dissolved solids; pH 8.0; metamorphics; 3 m above high tide mark; 16 vents	Goodbrand & Crandall (1977) Souther (1976)
93D-2	Ocean Falls	52 22 127 40	..	..	..	Alleged to be 5 km north of Ocean Falls on west side of Link Lake; quartz diorite-granodiorite	Goodbrand & Crandall (1977)
93D-3	Bella Coola	52 23 126 46	..	..	..	Alleged to occur on the tidal flats at or northwest of Bella Coola	Goodbrand & Crandall (1977) Souther & Halstead (1973)
93D-4	Eucott Bay	52 29 127 20	54	10	7000	3384 ppm total dissolved solids; 7 vents issuing from fractures; granodiorite; at and above high tide mark	Goodbrand & Crandall (1977) Souther (1976) Souther & Halstead (1973)
93D-5	Ram Bluff	52 27 127 15	..	..	..	Alleged to occur at Ram Bluff on Labouchere Channel	Goodbrand & Crandall (1977) Souther & Halstead (1973)
93D-6	Nascall Bay	52 28 127 16	43.4	1	600	2 vents; quartz diorite; occurs in heavily forested valley bottom	Goodbrand & Crandall (1977) Souther & Halstead (1973)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
93N-1	Tchentlo	55 13 125 16	..	..	..	Alleged to occur on the south side of Tchentlo Lake, at the outlet from Purvis Lake	Perry (1979)
93O-1	Hudson Hope	55 59 122 00	..	..	..	Alleged to occur on the north bank of the Peace River at Hudson Hope; several vents; large deposits of tufa	McDonald (1978) Waring (1965)
94F-1	Prophet River	57 39 124 01	..	..	..	Alleged to occur 50 kilometres west of the Alaska Highway on the Prophet River	McDonald (1978)
94G-1	Trutch	57 44 122 58	..	..	..	Reported to be near the east end of the Trutch airstrip, on the Alaska Highway	File

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
94K-1	Toad River	58 55 125 04	..	..	..	Occurs 2.5 km north of Alaska Highway at the junction of the Toad & Racing Rivers	Souther & Halstead (1973) Waring (1965)
94M-1	Portage Brule	59 38 126 57	48	15	10,000	1103 ppm total dissolved solids; HCO_2 dominant; 8 seeps in fractured pelitic limestone; a SP traverse gave a +20 mV response	Crandall & Sadlier-Brown (1976) Souther (1976)
94M-2	Liard	59 25 126 05	40	70	40,000	851 ppm total dissolved solids, SO_4 dominated; 2 vents in the west limb of a anticline; clastic sediments overlying limestone; developed as a provincial park and for public bathing	Crandall & Sadlier-Brown (1976) Souther (1976)
94N-1	Deer River	59 30 126 00	42?	..	..	Alleged to occur 14 km northeast of Liard Springs	Crandall & Sadlier-Brown (1976)
95C-1	Larsen	60 12 125 30	48	35	20,000	390 ppm total dissolved solids; pH 7.3; 2 vents issuing from carbonates near Devonian, Mississippian contact	Crandall & Sadlier-Brown (1976)
95C-2	Pool Creek	60 23 125 32	51	10	7,000	450 ppm total dissolved solids; pH 7.3; issuing from Devonian Carbonates; 1 vent	Crandall & Sadlier-Brown (1976)
95D-1	Coal River	60 08 127 25	13	45	5000	326 ppm total dissolved solids; pH 7.5; 1 vent issuing from Silurian-Devonian carbonates; tufa deposit	Crandall & Sadlier-Brown (1976)
103B-1	Hot Spring Island	52 35 131 27	76	4.3	5000	1332 ppm total dissolved solids; granodiorite; several springs; located on southwest side of Hot Spring Island	Goodbrand & Crandall (1977) Souther (1976)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
103H-1	Khutze Inlet	53 58 128 25	..	..	..	Alleged to occur at the head of Khutze or Aaltanhash Inlets	Goodbrand & Crandall (1977) Souther & Halstead (1973)
103H-2	Klekane	53 15 128 40	49	4	3000	423 ppm total dissolved solids; pH 7.7; quartz diorite; 2 vents; heavily forested valley bottom	Goodbrand & Crandall (1977) McDonald (1977)
103H-3	Goat Harbour	53 22 128 53	44	..	..	372 ppm total dissolved solids; metamorphic in Coast Plutonic Complex; 1 vent	Goodbrand & Crandall (1977) McDonald (1977)
103H-4	Shearwater	53 27 128 34	45	8	5000	1168 ppm total dissolved solids; pH 7.7; chloritic schist; shoreline Coastal Mountains; 5 vents	Goodbrand & Crandall (1977)
103H-5	Bishop	53 28 128 50	44	1	600	288 ppm total dissolved solids; pH 9.1; granodiorite; steep heavily forested slopes 1 vent	Goodbrand & Crandall (1977) McDonald (1977) Souther & Halstead (1973)
103H-6	Hartley Bay	53 26 129 15	..	..	..	Alleged to occur 3 km north of Hartley Bay on the west side of Douglas Channel	Goodbrand & Crandall (1977)
103H-7	Brim River	53 31 128 22	38	..	..	278 ppm total dissolved solids; quartz diorite; situated in river valley bottom; 1 vent	Goodbrand & Crandall (1977) McDonald (1977) Souther & Halstead (1973)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
103H-8	Weewannie	53 42 128 47	47.5	1	600	768 ppm total dissolved solids; pH 8.6; granodiorite; shoreline Coast Mountains; 1 vent	Goodbrand & Crandall (1977) McDonald (1977)
103I-1	Frizzel	54 13 129 55	46	10	6000	831 ppm total dissolved solids; pH 7.9; Coast Plutonic Complex; 3 vents	Goodbrand & Crandall (1977) Souther (1976)
103I-2	Lakelse	54 22 128 35	85	6	10,000	1120 ppm total dissolved solids; pH 7.9;. Coast Plutonic Complex; located in flat valley bottom, developed as Skoglund's Hot Spring Resort; 3-12 vents	Goodbrand & Crandall (1977) McDonald (1977) Souther (1976) Souther & Halsteao (1973)
103I-3	Burton	54 55 129 50	45	..	..	1425 ppm total dissolved solids; pH 7.4; Coast Plutonic Complex; located in creek valley; 1 vent	Goodbrand & Crandall (1977) Souther (1976)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

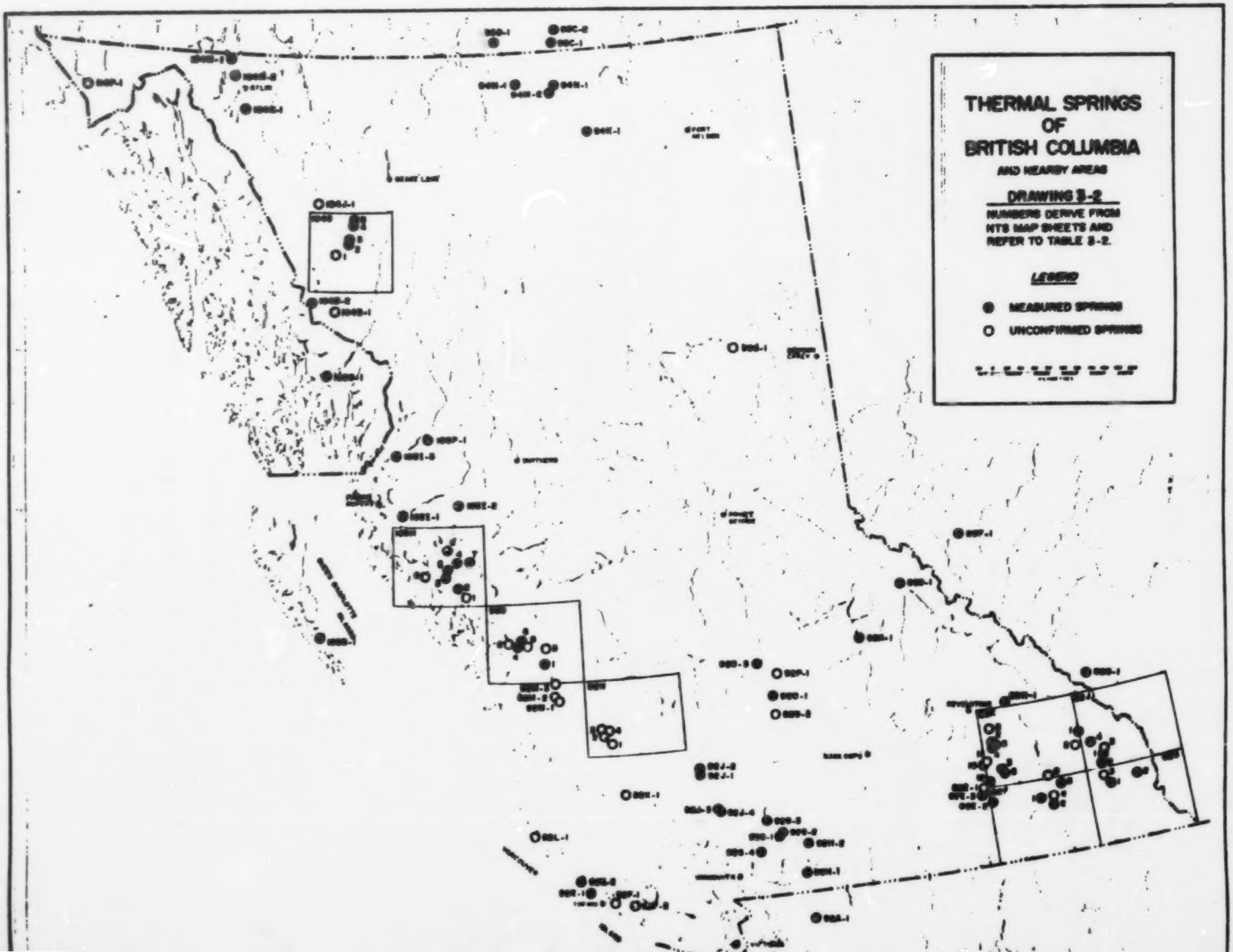
Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
103O-1	Bell Island	55 59 131 34	60	.5	400	623 ppm total dissolved solids; occurs in granite cut by pegmatite dykes	Waring (1965) Hutchinson et al (1979)
103P-1	Zolzap	55 07 129 21	..	..	..	Coast Plutonic Complex; recent volcanic activity in area	Goodbrand & Crandall (1977) McDonald (1977)
104B-1	Hoodoo Mountain	56 40 131 15	..	..	..	Alleged to occur on south side of Iskut River across from Hoodoo Mountain	Goodbrand & Crandall (1977)
104B-2	Stikine	56 50 131 45	65.5	44	40,000	847 ppm total dissolved solids; granodiorite; located opposite Fowler (abandoned) near base of Warm Springs Mountain; several vents	Goodbrand & Crandall (1977) Waring (1965)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
104G-1	Sphaler Creek	57 03 131 10	..	..	..	Alleged to occur at 914 metre elevation, at the head of Sphaler Creek	Goodbrand & Crandall (1977) McDonald (1978)
104G-2	Mess Creek	57 25 130 55	41.5	3	2000	1552 ppm total dissolved solids; pH 6.5; Paleozoic sediments on the flank of Mt. Edziza; calcite deposit replacing moss along lake edge; 1 vent	Goodbrand & Crandall (1977) McDonald (1978) Souther (1976) Souther & Halstead (1973)
104G-3	Mess Lake	57 27 130 53	10	1	100	6361 ppm total dissolved solids; pH 6.4; Paleozoic sediments on the flank of Mt. Edziza; formed a hill of travertine 15 m high by 30 m wide by 45 m long; six mounds of calcite in 1-acre area, each 2 m in diameter	Goodbrand & Crandall (1977) McDonald (1978) Souther (1976) Souther & Halstead (1973)
104G-4	Tawah Creek	57 42 130 47	43	4	2000	2376 ppm total dissolved solids; pH 9.8; Paleozoic sediments; tufa deposits along creek; 1 vent	Goodbrand & Crandall (1977) McDonald (1978) Souther (1976) Souther & Halstead (1973)
104G-5	Elwyn Creek	57 48 130 46	25	3	900	3539 ppm total dissolved solids; pH 7.3; Mt. Edziza volcanics; large tufa deposits; 6 vents	Goodbrand & Crandall (1977) McDonald (1978) Souther (1976) Souther & Halstead (1973)

Table 3-2 BASIC DATA ON THERMAL SPRINGS

Reference number	Name of spring	Latitude (N) Longitude (W) degrees & minutes	Maximum noted Temperature (°C)	Estimated discharge (litres/sec)	Wasted heat above 5°C (10^6 joules/hr)	Comments on chemistry, geology, physical setting	Latest references
104J-1	Sheslay	58 22 131 52	..	..	..	Alleged to occur 16 km north of Sheslay on the east side of the river at 600 metres asl	McDonald (1978) Goodbrand & Crandall (1977)
104M-1	Morin South	59 58 134 13	14	20	3000	255 ppm total dissolved solids; pH 7.4; sedimentary rocks; tufa; 2 vents	Crandall & Sadlier-Brown (1976)
104N-1	Atlin	59 24 133 35	29	45	20,000	253 ppm total dissolved solids; pH 8.2; sedimentary rocks; SP traverse gives +65mV; small accumulation of tufa	Crandall & Sadlier-Brown (1976) McDonald (1978) Souther (1976) Souther & Halstead (1973)
104N-2	Jones Lake	59 53 134 00	13	45	5000	233 ppm total dissolved solids; pH 7.6; sedimentary rocks	Crandall & Sadlier-Brown (1976)
114P-1	Tatshenshini	59 30 127 40	..	..	..	Alleged to occur on the south side of Tatshenshini River, near its' mouth on the Alsek River	File



THERMAL SPRINGS
OF
BRITISH COLUMBIA
AND NEARBY AREAS

DRAWING 3-2

NUMBERS DERIVE FROM
NTS MAP SHEETS AND
REFER TO TABLE 3-2.

LEGEND

● MEASURED SPRINGS
○ UNCONFIRMED SPRINGS

known. Included in the table and drawing is the designation "unconfirmed springs". Unconfirmed springs are those which have not yet been described in detail by a geologist or other technical worker. The story of their existence, location and properties is vague and has been passed down orally or in written records for many decades, generally originating from a single source. Some unconfirmed springs are based on reports, from prospectors or bush pilots, of small snow-free and "steaming" areas. In some instances serious attempts have been made to confirm some of these springs without success.

Data on known springs include maximum measured temperature, estimated rate of discharge (which is generally imprecise), and a calculated value of "wasted" heat according to the formula:

$$Q = (T-5) \times f \times 15.1,$$

where, T = temperature of hot spring in degrees Celsius,
f = flow in litres/second,
15.1 is a constant conversion factor,
and Q = wasted heat in megajoules per hour.

The result is simply an index, in addition to temperature, of the thermal properties of the spring. It presumes an ambient "atmosphere" of 5°C. Results are rounded to one significant figure in view of the lack of precision in most estimates of flow rate.

There are very few analytical or summary comments which can be made based on existing hot spring data. We submit (referring to the discussions of natural geothermal systems and exploration methods in Appendices C and D) that most springs are probably mixtures of geothermal water and groundwater, that data acquisition is in its infancy, that considerably more data are needed, and that as these data are acquired on a systematic basis some of the thermal waters will yield clues as to whether or not a commercial geothermal resource may exist in the subsurface.

3.3 Distribution of Young Volcanic Rocks

More meaningful in the exploration for high temperature geothermal resources is the distribution of volcanic rocks of late Cenozoic age. These rocks are summarized and catalogued in Table 3-3 and Drawing 3-3

- - - - - - - - - - - - - - -

Table 3-3 (8 pages) and
Drawing 3-3 follow

- - - - - - - - - - - - - - -

using the same system as for hot springs.

This information derives from decades of systematic geologic mapping at scales of 1:250 000 or greater. Most of this work was carried out by researchers of the Geological Survey of Canada (GSC) and by professors or students of geology at the University of British Columbia

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Mt. Baker 92A-1	48 45 121 50	Quaternary	100	92A-1	A stratavolcano composed exclusively of andesite flows. Basement rocks are Paleozoic to lower Tertiary sedimentary and metamorphic rocks.	Situated in the northern Cascade Ranges.	
Mt. Garibaldi 92G-1	49 52 123 01	Plio-Pleistocene to Recent	210	92G-4	Large stratavolcano composed of flows and pryoclastics up to 600 meters thick; andesite, dacite, rhyodacite; basement rocks are quartz diorite and metamorphic units of Cretaceous and earlier age	Situated in the Coast Plutonic Belt at the southern end of the north-northwest trending Garibaldi Group	Roddick (1965) Bostock (1963) Mathews (1958)
Meager Creek 92J-1	50 38 123 44	2.0 Ma to 2400 years	75	92J-1 92J-2	Three main volcanic periods produced a layer sequence up to 500 meters thick of rhyolite tuff, and andesite, dacite and rhyodacite flows and breccia. The most recent activity was the eruption of the Bridge River ash and overlying rhyodacite flow. At least nine vent areas are recognized in a north-south zone bisecting the Complex; volcanic activity progressed south to north; basement rocks are Cretaceous quartz diorite containing roof pendants of Triassic metamorphic rocks	Situated in the Coast Plutonic Belt at the northern extremity of the north-trending belt of the Garibaldi Volcanic Group	Read (1979) Fairbank et. al. (1980) Woodsworth (1977) Lewis et. al. (1979)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Mt. Cayley 92J-2	50 07 123 17	0.1 to 1.3 Ma	60	92J-3 92J-4	Several separate volcanic centres and partially overlapping complexes along a 18 km north-south zone. Porphyritic basalt, andesite, dacite, and rhyodacite flows, domes and breccia; basement rocks are quert diorite, granodiorite and metamorphic rocks of the Coast Plutonic Belt	Part of the Garibaldi Group overlying the Coast Plutonic Belt. Faults have locally displaced the volcanics up to 150 meters	Souther (1980)
Elaho 92J-3	50 28 123 26	0.15 Ma (whole rock K-Ar)	30	--	A number of small basalt to rhyodacite flows and plugs occur between the Meager Creek and Mt. Cayley complexes over a distance of 25 kilometers	Part of the north-northwest trending Garibaldi Group	Woodsworth (1977)
Port MacNeill 92L-1	50 35 127 16	K-Ar age on basalt 7.9 Ma	35	--	Basaltic to dacitic flows, tuffs, and breccia. Miocene to Pliocene volcanics overlie Triassic Karmutsen Formation volcanics	Within the Insular Belt on Vancouver Island and is confined along the Brooks Peninsula fault zone which transects the northwest regional trend	Muller et. al. (1974)
Mt. Silverthrone 92N-1	51 30 126 00	7.8-18 Ma	approx. 200	--	Deeply eroded composite volcano and cauldron complex	Coast Plutonic Belt	Souther (1976)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Quesnel 93A-1	52 10 121 02	Pleistocene to recent	50	--	Two volcanos, one post and one inter-glacial, and associated basaltic flows, breccia and tuff	Straddles the Intermontane Belt, situated at the center of Oligocene Miocene plateau basalts which cover the Interior Plateau	Tipper et.al. (1979) Tipper (1969)
Takomkane 93A-2	52 07 120 55	Plio-Pleistocene	2	--	An isolated basaltic volcano similar in occurrence to the Quesnel volcanic group	Intrudes and overlies the Takomkane batholith on the eastern margin of the Intermontane Belt	Tipper et. al. (1979) Campbell (1961;1963)
Clearwater 93A-3	52 02 120 03	Pliocene to Recent	300	93A-1	Comprised of at least four post-glacial cinder cones, several glaciated cones, one inter-glacial volcano (Pyramid Mtn.), associated basaltic valley flows, and older (Pliocene) plateau basalts	Lies within the Omineca Crystalline Belt	Tipper et. al. (1979) Campbell (1963) Campbell & Tipper (1971)
Nazko 93B-1	52 55 123 40	Recent	30	--	Basaltic flows, breccia, and ash with at least one volcanic cone present	Situated within the Intermontane Belt	Tipper et. al. (1979) Tipper (1957)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Downton 93C-1	52 36 124 50	Pliocene to Pleistocene	80	--	Several cinder cones of basaltic flows, breccias, and scoria overlie earlier (Miocene, Pliocene) plateau basalt. Flow-banded andesite, dacite, minor rhyolite and ash at Mount Downton represent a late Tertiary eruptive centre for the plateau basalt	Complex lies in the Intermontane Belt situated at the center of Oligocene Miocene plateau basalts which cover the interior plateau	Tipper et. al. (1979) Tipper (1969)
Sustut 94D-1	56 16 126 32	Miocene ro Recent	30	--	Isolated basalt flows, flow breccia, and associated dykes and small plugs intrude and overlie Eocene to Upper Cretaceous sedimentary rocks of the Sustut Basin	Northwest trending zone of folding and reverse faults within the Intermontane Belt	Richards (1975) Eisbacher (1973)
Lake Island 103A-1	52 25 128 38	Pleistocene to Recent	14	--	Reddish brown to black unconsolidated ash, agglomerate, scoria, and basaltic flows. Two post-glacial cones are present	Within the Coast Plutonic Complex, at the junction of the Grenville Channel and Principe Laredo faults	Hutchinson et. al. (1979) Baer (1973)
Behm Canal 103O-1 (USA)	55 20 131 00	Pleistocene to Recent	100	--	Basaltic and andesitic flows; Three cones	Located on the western Coast Plutonic Belt along a zone of north-northwest trending faults	Hutchinson et. al. (1979)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Nass 103P-1	56 10 129 05	Pleistocene to Recent	150	103P-1	Several separate basaltic flows and ash falls; one cinder cone is present in the area	At the west margin of the Intermontane Belt	Hutchinson et. al. (1979) Brown (1969)
Iskut 104B-1	56 35 131 00	Pleistocene to Recent	100	104B-1	Four geographically separate volcanos and associated basaltic flows; the largest of the volcanos (Hoodoo Mtn.) is a glacially modified composite cone	Situated on the eastern margin of the Coast Plutonic Complex	Kerr (1948) Souther et. al. (1979)
Edgecumbe 014E-1 (USA)	57 05 134 45	Recent	100	--	Basaltic flows, ash and lapilli tuffs from five main vents	Within hte Insular Belt along a zone of transcurrent faulting between the North American and Pacific Plates (Fairweather fault)	Souther et. al. (1979)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Mount Edziza 104G-1	57 45 130 44	Pliocene to Recent	1200	104G-1 104G-2 104G-3 104G-4 104G-5 104G-6	At least four cycles of volcanism; each starts with a large outflow of fluid basalt and ends with restricted flows of more acidic magma; the composition of flows ranges from olivine basalt to trachyte to soid rhyolite; six pyroclastic cones in the complex, some of which have not been glaciated	Intrudes and overlies rocks of the Stikine Arch within the Intermontane Belt; lies on the eastern margin of the Coast Plutonic Belt and parallels the direction of early Tertiary block faulting	Souther et. al. (1979), Souther & Symons (1974), Souther (1972) Souther (1970)
Eagle River 104I-1	58 30 129 30	Miocene to Recent	80	--	Geographically isolated volcanic centres with both glaciated and unglaciated cinder cones; restricted flows from these centres consist of basalt and olivine basalt	Straddles the junction of the Stikine Arch in the Intermontane Belt and Omineca Crystalline Belt near where the Atlin horst terrane pinches out	Souther et. al. (1979) Garbrielse (1962)
Kechika 104I-2	58 50 128 00	Miocene to Pleistocene	50	--	Rhyolite, siliceous tuff, and chalcedonic rhyolite breccia; may be the remnant of a stratavolcano	Lie on the eartern margin of the Omineca Crystalline Belt, straddling the Dall Lake Fault	Souther et. al. (1979) Gabrielse (1962) McLean & Kindle (1950)

TABLE 3-3

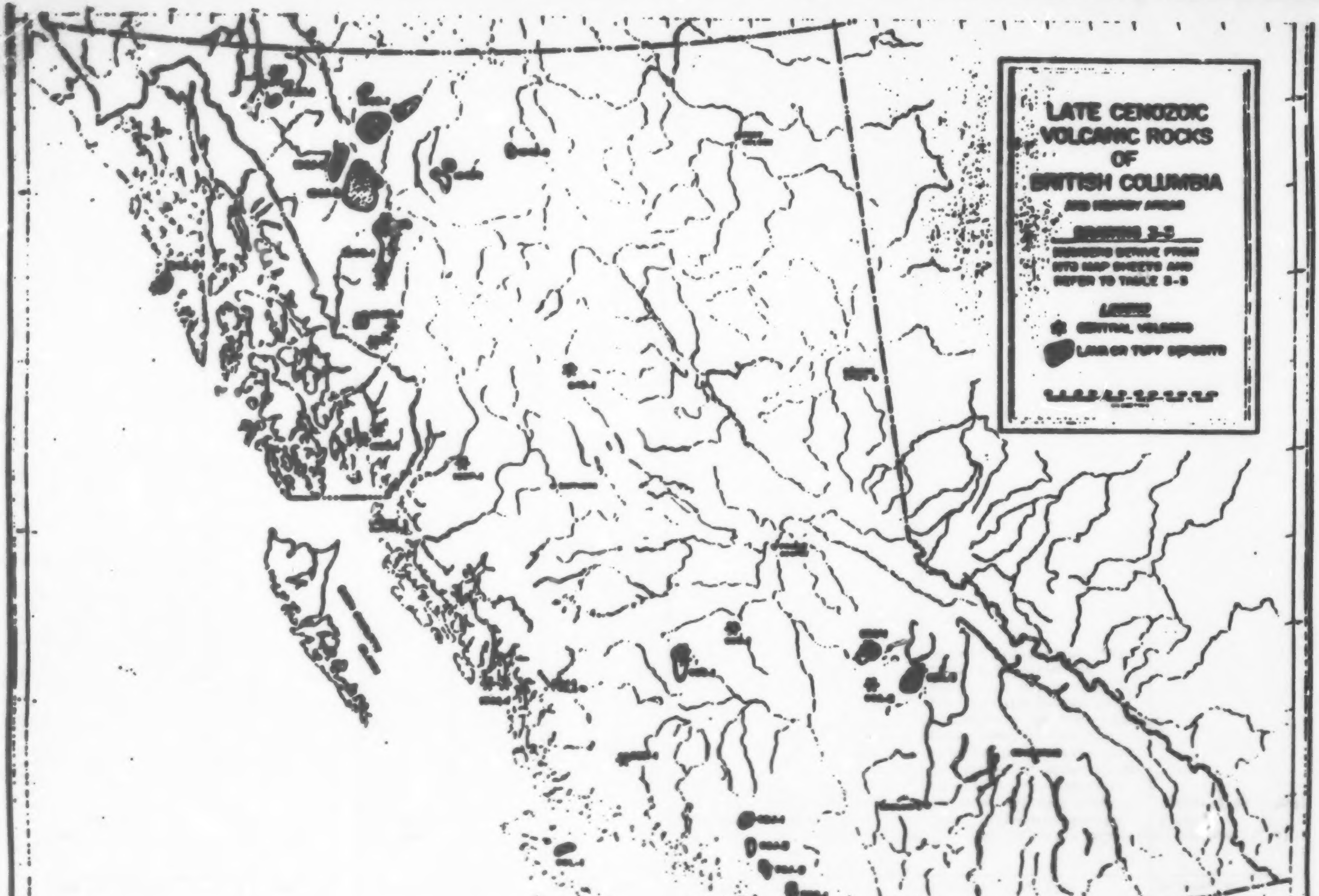
LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Heart Peaks 104J-1	58 35 132 00	Miocene to Pleistocene	250	--	Rhyolite and trachytic lavas overlain and interbedded with flood basalt	15 kilometers west of Level Mountain on top of an early Tertiary erosional surface within the Intermontane Belt	Souther et. al. (1979) Souther (1971)
Level Mountain 104J-2	58 31 131 20	Miocene to Recent	1800	104I-1	Shield volcano comprised of three main lava types: 1) andesitic pyroclastics of the early Tertiary, 2) alkalic basalts of Miocene, Pliocene and Pleistocene age, and 3) trachyte, rhyolite and sodic rhyolite of Pleistocene and Recent age	Intermontane Belt; lava types imply two depth origins: early alkalic basalt indicates a deep mantle source and sodic rocks imply a relatively shallow source	Hamilton & Scarfe (1977) Souther et. al. (1979) Souther (1971)
Atlin 104N-1	59 40 133 25	Miocene to Pleistocene	50	104N-1	Geographically isolated flows and small cones of at least two distinct ages; pre-glacial volcanos occur in four areas and are composed of olivine basalt; younger flows originate from two cones northwest of Surprise Lake and are glacial to post-glacial in age	In the Atlin horst terrane. The younger volcanics occur at the eastern edge of the Fourth of July Creek Batholith. Older volcanics occur on or near normal faults to the north of the Mt. McMaster Stock	Souther et. al. (1979) Aitken (1959)

TABLE 3-3

LATE CENOZOIC VOLCANIC COMPLEXES IN BRITISH COLUMBIA (AND NEARBY)

Name of Complex	Latitude (N) Longitude (W)	Age(s)	Areal Extent (sq km)	Nearby Hot Springs	Description and Lithology	Geological Setting	Latest References
Tuya 104C-1	50 15 130 45	Miocene to Recent	350	--	The Tuya Formation is composed of a group of widespread eruptive centers and isolated basaltic flows	The Tuya Formation volcanics occur as geographically isolated volcanic centres in a zone approximately 80 kilometers wide, elongated north-northeast from Level Mountain for 150 kilometers. The zone extends E-W from the Nanlin Fault across the Atlin horst terrane and into the Omineca Crystalline Belt	Souther et. al. (1979) Gabrielse (1969)


LATE CENOZOIC
VOLCANIC ROCKS
OF
BRITISH COLUMBIA
AND NEARBY AREAS
NUMBERS DERIVE FROM
NTS MAP SHEETS AND
REFER TO TABLE 3-5
LEGEND
CENTRAL VOLCANO
LAVA OR TUFF DEPOSITS

and other universities. Generally the purpose of this mapping is pure research: to identify and measure various rocks and their properties and develop geologic models for the evolution of the crust.

Other contributors to the literature on general geology are associated with the B.C. Ministry of Energy, Mines and Resources and with the private sector, although the attention of these geologists is not generally drawn to late Cenozoic volcanos.

The geologic references are far too numerous to review in this report. Principal references are listed in Table 3-3. Any person familiar with geologic literature can quickly review the chain of citations and establish the complete body of information for a given area. As it happens, many of the geologists responsible for the cited works are active at the present time and can be contacted directly.

In Table 3-3 we have made an attempt to collate certain data which may be of comparative value in assessing geothermal potential. The age or age span of volcanism is reported, following the original author. Geologic ages are given where radiometric dates have not been reported. (See appendix B for age terminology.) The table lists volcanic rocks only as far back as Mio-Pliocene. The extensive flood basalts of the Cariboo and Chilcotin regions (of the Intermontane Belt) are omitted as being too old, Paleocene to Miocene in age.

The areal extent of the present outcrops of volcanic rocks is also listed. This is generally our estimate based upon the principal references. Although this figure may convey a preliminary indication of the extent of volcanic rocks, it is subject to some variance and interpretation. The original extent of volcanic rocks may have been significantly reduced by subsequent erosion, and the remnants may have little relationship to the original volume. Secondly, volume is of more importance in assessing the relative strength of a system than areal extent. The volume would have to be derived by integrating the thickness over the area of remnant outcrop or inferred original distribution.

Summary comments on lithology and geologic setting are also given.

Different geologists look for different features in assessing the geothermal potential of areas underlying late Cenozoic volcanic rocks. Most would agree that thin flows of basaltic composition are less attractive than composite central volcanos having a composition centering on dacite or andesite. Most geologists seek evidence that subvolcanic intrustions are present, i.e., that a large remainder of igneous material which did not erupt is present beneath a prospective volcanic system. Ring-shaped collapse fractures around a volcanic system may be considered as such evidence. Similarly, widely spaced late-stage cinder cones may be considered evidence of large subvolcanic bodies.

3.4. Structural Geology

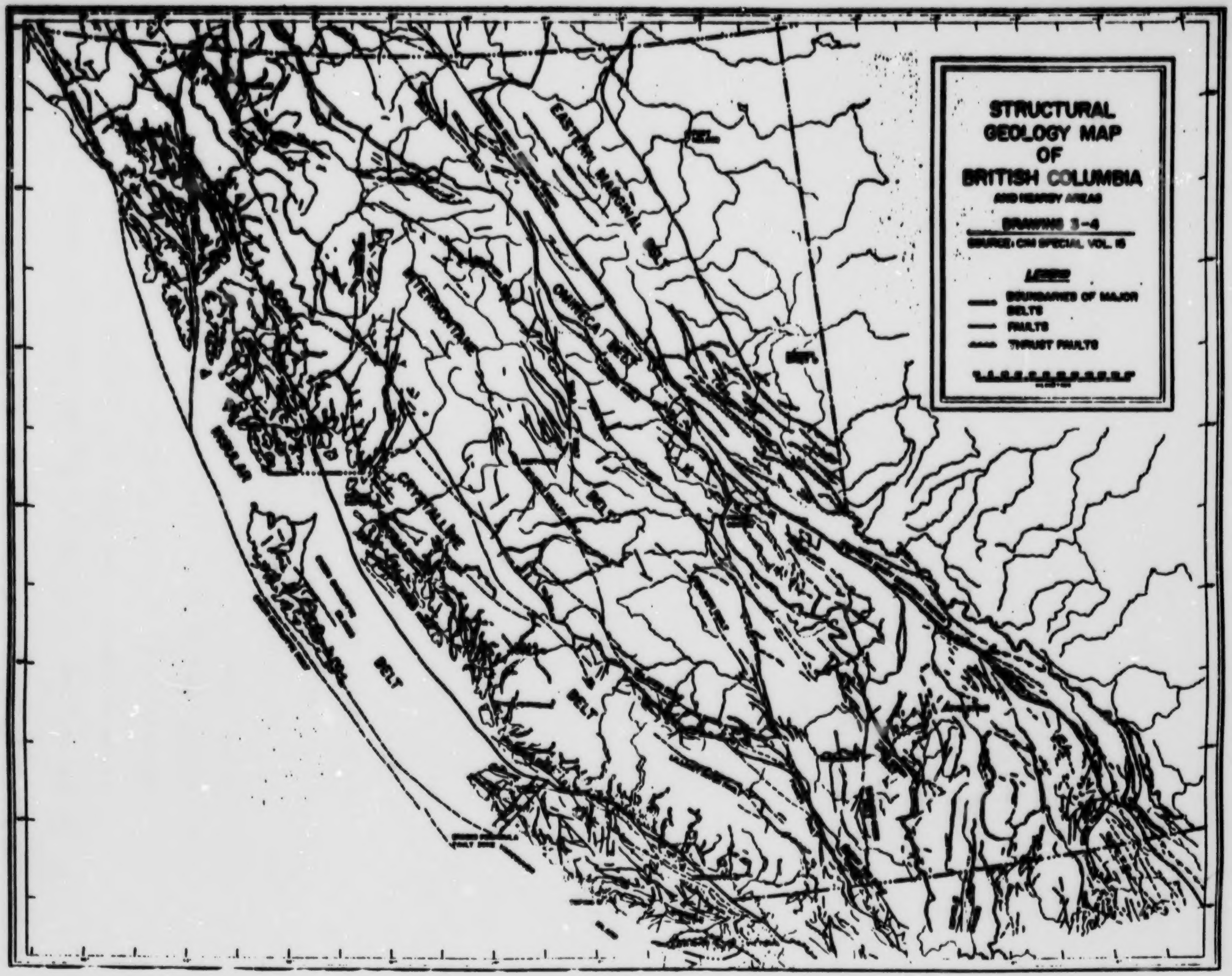
Another outgrowth of systematic regional geologic mapping is the identification and description of the various elements of structural geology, shown in Drawing 3-4. The province of British Columbia has been divided into five parallel northwest trending belts, each having distinctive geology. From west to east these are the Insular Belt, the Coast Crystalline Belt, the Intermontane Belt, the Omineca, and the Eastern Marginal Belt which terminates at the Rocky Mountain front.

- - - - - - - - - - -

Drawing 3-4 follows

- - - - - - - - - - -

The Insular Belt is characterized by Mesozoic volcanic rocks and coeval intrusives, and is sliced by deeply seated faults, including major transform faults associated with presently active continental and oceanic plate movement. The Coast Crystalline Belt is dominated by coallescing bodies of Mesozoic granitic rocks. High


STRUCTURAL
GEOLOGY MAP
OF
BRITISH COLUMBIA
AND NEARBY AREAS
DRAWING 3-4
SOURCE: CIM SPECIAL VOL. 15
LEGEND
BOUNDARIES OF MAJOR BELTS
FAULTS
THRUST FAULTS
EASTERN MARGINAL BELT
OMINECA BELT
INTERMONTANE BELT
CRYSTALLINE BELT
INSULAR BELT

mountain ranges are present within the belt; access is difficult in places; the geology is mapped to a lesser extent than elsewhere; and throughgoing faults and structures are more difficult to identify.

The Intermontane Belt is underlain by sedimentary and volcanic rocks generally ranging in age from late Paleozoic through early Mesozoic. Local intrusive bodies are present. In places such as the Cariboo and Chilcotin areas, the older rocks are overlain by early Cenozoic volcanics. Part of the northern Intermontane Belt is overlain by younger sedimentary rocks of the Bowser Basin.

The Omineca Belt includes a wide variety of metamorphic rocks, some of which are the equivalents in age of the metamorphic rocks to the west and the sedimentary rocks to the east.

The Eastern Marginal Belt is made up of the folded and thrust-faulted Proterozoic and Paleozoic sedimentary rocks which constitute the Rocky Mountains. The boundary between the Omenica Belt and the Eastern Marginal Belt is a fault of continental magnitude reflected on the surface as the Rocky Mountain trench. The eastern boundary is the Rocky Mountain front, and to the east lie the sedimentary basins of the northeastern part of the province, which includes the known oil and gas fields.

Certain large and deep seated regional faults are named in Drawing 3-4. Other major faults are indicated by solid or dashed lines, depending upon the degree of certainty of their location. Faults are considered important by geologists working in any of the exploration industries. In geothermal applications fault systems may be of interest as localizing factors for volcanic or intrusive rocks, as conduits or reservoirs for geothermal fluids, or as boundaries between dissimilar geologic terranes.

It should be noted that the unequal distribution of faults shown in Drawing 3-4 is the result of three factors: a natural distribution which is unequal, a sampling bias which results from uneven levels of geologic mapping from place to place, and concealment of faults in places by post-faulting deposits of volcanic or sedimentary rocks, or glacial deposits and soil cover.

3.5 Northeastern Basins

It is quite certain that accessible and useful geothermal resources are present in the sedimentary basins underlying the northeastern part of B.C. This region contains the known and producing oil and gas fields in British Columbia. A generalized stratigraphic column for the region, adapted from Torrie (1973) and Sproule (1976, 1977) is presented as Drawing 3-5. Some geothermal data

- - - - - - - - - - - - -

Drawing 3-5 follows

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are known from downhole measurements and from the temperatures of flowing oil, gas and associated brines.

Depth of a particular water-rich aquifer may vary. A feeling for the geological complexity of the region can be gained by inspection of Drawing 3-6, a generalized

- - - - - - - - - - - - -

Drawing 3-6 follows

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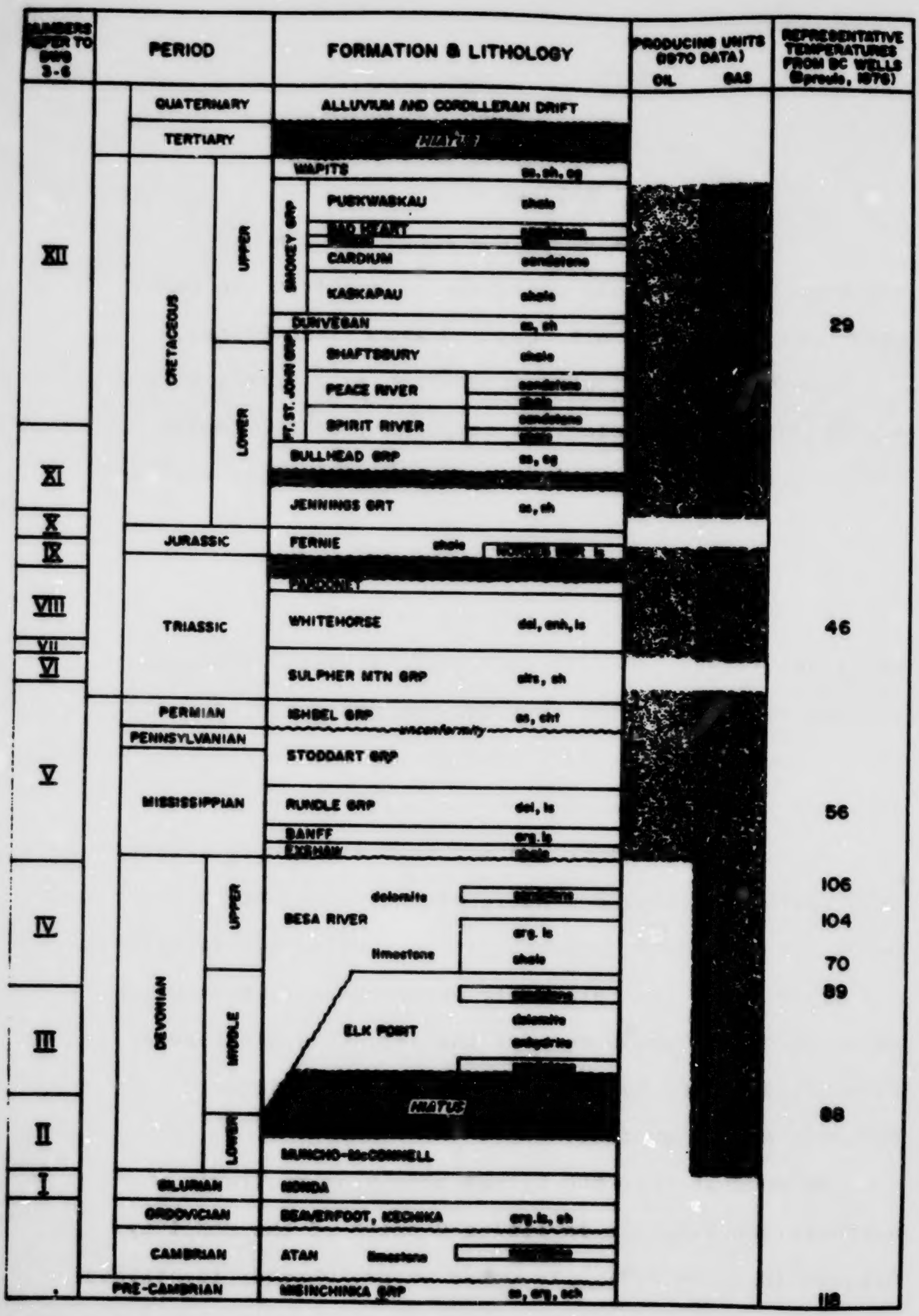
cross-section reproduced from Torrie (1973). The geothermal resource in the area has not been studied in detail, since all of the drilling in the region has been directed toward hydrocarbon exploration and production.

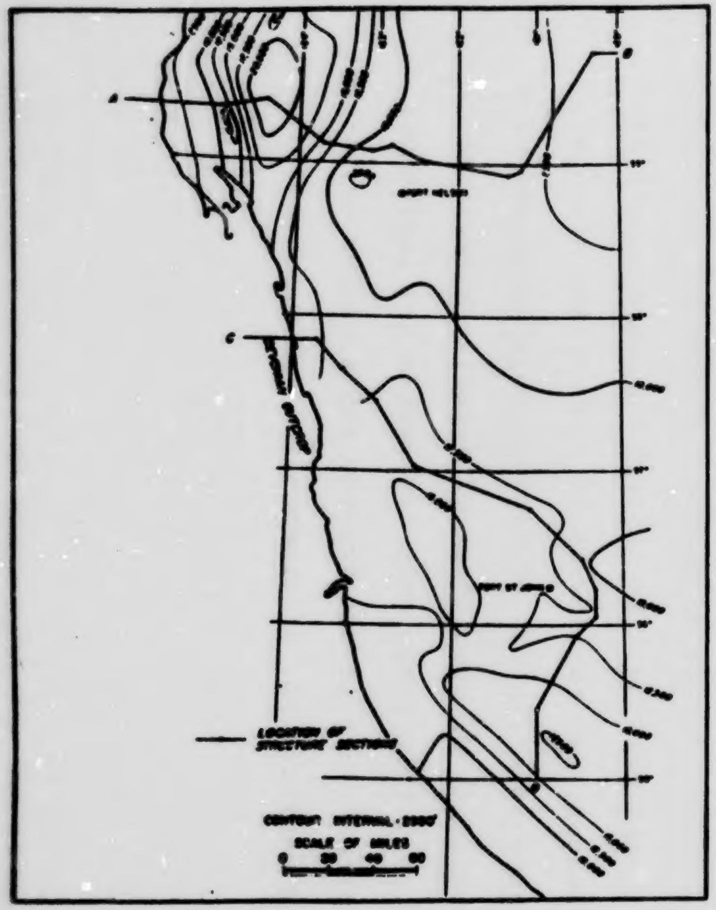
While there is little doubt that a resource exists, Reid Crowther (1980) demonstrates that utilization depends upon economic factors. In particular two factors are important: the relatively small thermal loads which exist or can be projected for the region, and the relative abundance of hydrocarbons having much higher specific energy content.

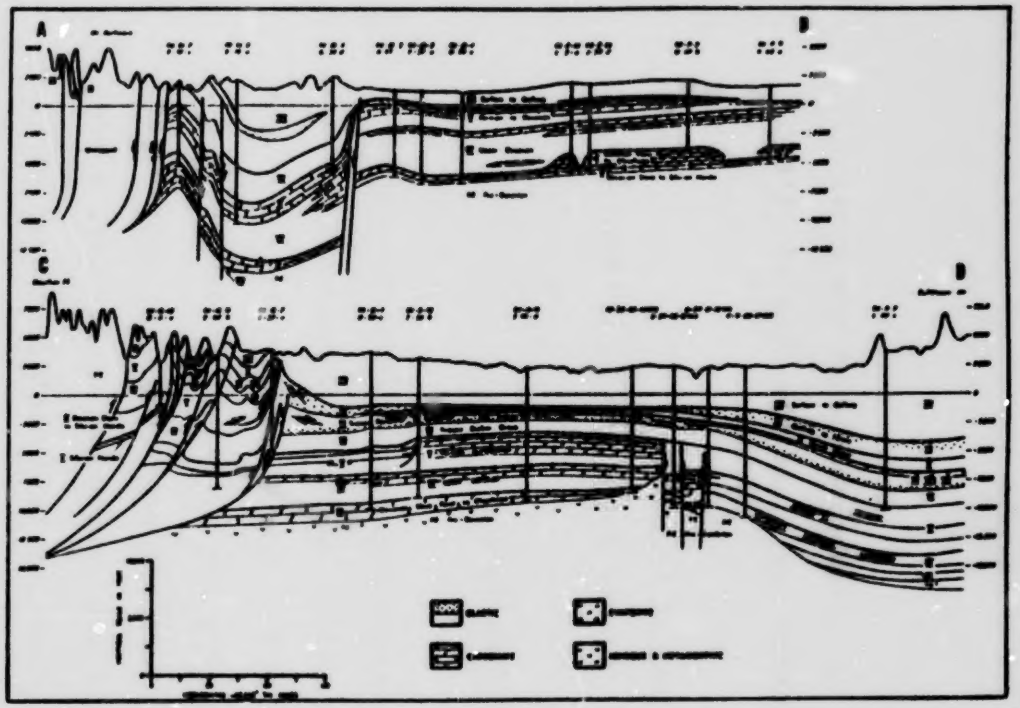
We suggest that the brines occupying aquifers in northeastern B.C. lie in fields C and D of the McKelvey diagram (Drawing 2-3). In other words, whether identified


NUMBERS REFER TO DWG 3-6
PERIOD
FORMATION & LITHOLOGY
PRODUCING UNITS (1970 DATA)
OIL
GAS
REPRESENTATIVE TEMPERATURES FROM BC WELLS (Sproule, 1976)
XII
XI
X
IX
VIII
VII
VI
V
IV
III
II
I
QUATERNARY
TERTIARY
CRETACEOUS
UPPER
LOWER
JURASSIC
TRIASSIC
PERMIAN
PENNSYLVANIAN
MISSISSIPPIAN
DEVONIAN
UPPER
MIDDLE
LOWER
SILURIAN
ORDOVICIAN
CAMBRIAN
PRE-CAMBRIAN
ALLUVIUM AND CORDILLERAN DRIFT
HIATUS
WAPITS
ss, sh, cg
SMOKEY GRP
PUSKWASKAU
shale
BAD HEART
sandstone
CARDIUM
sandstone
KASKAPAU
shale
DUNVEGAN
ss, sh
FT. ST. JOHN GRP
SHAFTSBURY
shale
PEACE RIVER
sandstone
shale
SPIRIT RIVER
sandstone
shale
BULLHEAD GRP
ss, cg
JENNINGS GRT
ss, sh
FERNIE
shale
PARDONET
WHITEHORSE
dol, anh, ls
SULPHER MTN GRP
slts, sh
ISHBEL GRP
ss, cht
unconformity
STODDART GRP
RUNDLE GRP
dol, ls
BANFF
arg. ls
EXSHAW
shale
dolomite
BESA RIVER
arg. ls
limestone
shale
ELK POINT
dolomite
anhydrite
HIATUS
MUNCHO-McCONNELL
NONDA
BEAVERFOOT, KECHIKA
arg.ls, sh
ATAN
limestone
MISINCHINKA GRP
ss, arg, sch
29
46
56
106
104
70
89
88
118

DRAWING 3-5

GENERALIZED STRATIGRAPHIC COLUMN OF ROCKS IN NORTHEASTERN B.C., WITH GEOTHERMAL DATA.


FORT NELSON
DEVONIAN OUTCROP
FORT ST. JOHN
LOCATION OF STRUCTURE SECTIONS
CONTOUR INTERVAL - 2000'
SCALE OF MILES
0 20 40 60



DRAWING 3-6

MAP AND GEOLOGIC CROSS-SECTIONS OF NORTHEASTERN B.C. REPRESENTATIVE OF SEDIMENTARY BASINS
(Thicknesses in feet)

Reproduced directly from:
Torrie, J.E. Northeastern British Columbia *in* The Future Petroleum Provinces of Canada, Their Geology and Potential, p 151-186, illus. (incl sketch maps), Can. Soc Pet. Geol., Calgary, Alberta, 1973.

or not, they appear to be subeconomic at the present time based on production costs and the cost of alternate fuels.

3.6. Opinion on Resources in B.C.

Several shaded regions are shown in Drawing 3-7.

- - - - - - - - - - -

Drawing 3-7 follows

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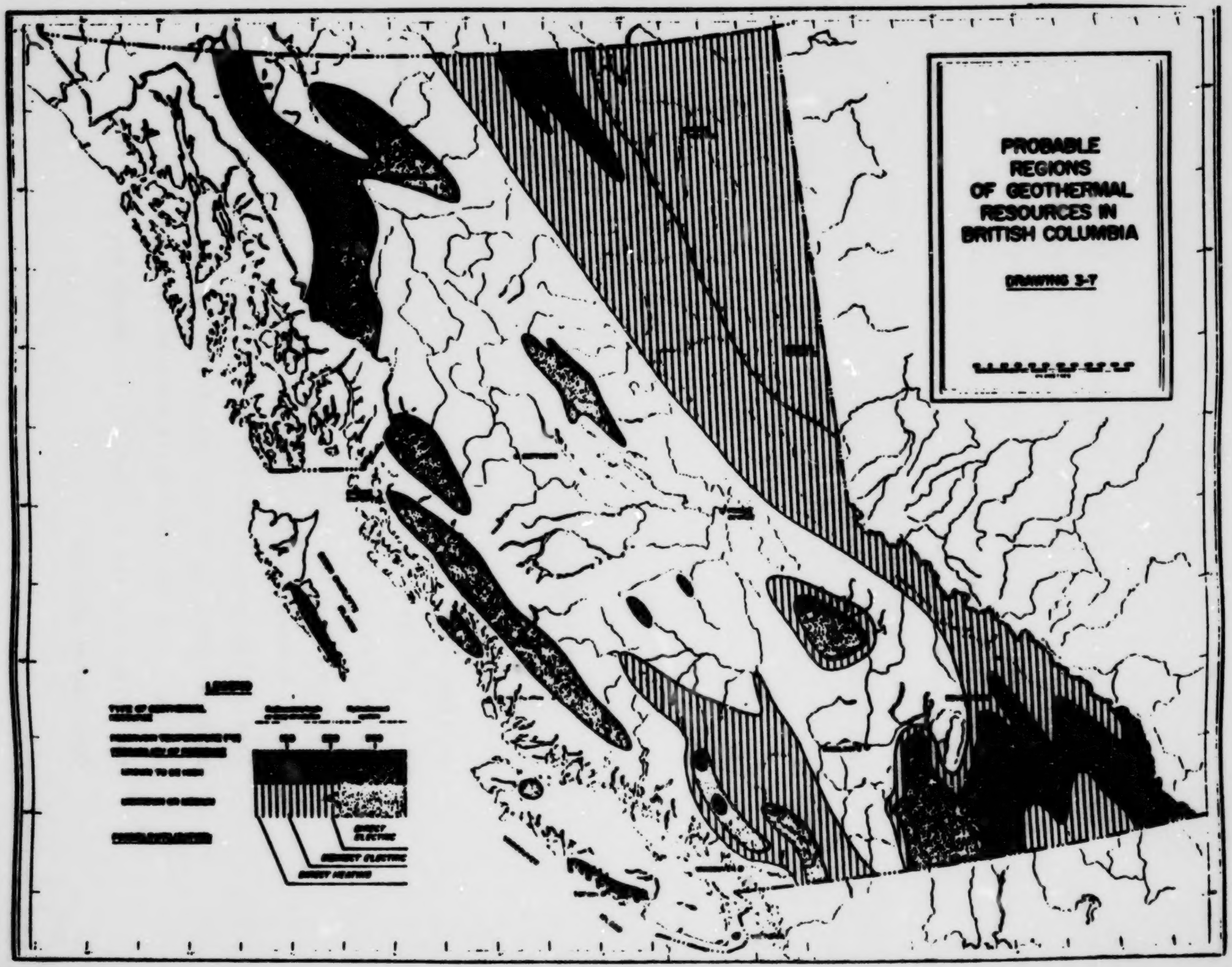
As the drawing indicates, high temperature hydrothermal resources, 200°C or hotter, might be considered for application to direct conversion to electricity, indirect conversion by means of a binary plant, or direct use. Intermediate temperature resources might be considered for indirect electric conversion and direct use; where as those resources generally less than 100°C can be considered only for direct heating.

Certain inferences on the probability for occurrence of the various classes of geothermal resource are illustrated in the drawing. If exploration were in its advanced stages, several levels of probability could be shown, such as are shown on various maps concerned with the probability of occurrence of metallic mineral resources. At this stage only two levels are indicated: a high probability of occurrence, and a medium or unknown probability for occurrence.



LEGEND
DIRECT ELECTRIC
INDIRECT ELECTRIC
DIRECT HEATING

PROBABLE REGIONS OF GEOTHERMAL RESOURCES IN BRITISH COLUMBIA

DRAWING 3-7

Drawing 3-7 is very subjective. It might be drawn differently by different geologists. Altogether six geologists with experience in geothermal exploration and in the geology of British Columbia had a hand in the construction of Drawing 3-7.

The patterned regions are not meant to imply the existence of geothermal resources underlying the entire region; they are meant to describe regions of higher probability in which exploration could logically begin. If exploration amounts to looking for a needle in a haystack, the patterned regions are haystacks. The following comments will explain our assessment and designation of each area.

Southwestern Mainland. The Meager Creek and Mount Cayley volcanic systems lie in this area and are believed to have high potential for high temperature resources. These two areas are part of a geologic belt which extends southeastward through Squamish, Garibaldi Park and to the Pitt River. A subparallel belt extends northward from the vicinity of Mt. Baker, in Washington State, through Harrison Hot Springs and along Harrison Lake. This zone is defined by a volcano, several hot springs, and a large regional fault. An envelope surrounding both of these belts extends northward along the Fraser and the Yalakom Faults, which are part of a deep-seated system.

Okanagan. Although there are no known thermal springs or Recent volcanos in the Okanagan, the geology is dominated by a block-faulted terrane. This is a continuation of a larger terrane in the U.S. and it implies crustal extension, or pulling apart. It is an area of some prospective probability for the occurrence of high temperature geothermal resource.

Vancouver Island. Two distinct areas are indicated where high temperature geothermal resources might exist on Vancouver Island. Nevin Sadlier-Brown Goodbrand Ltd. (1975b), assessed the southern area on behalf of B.C. Hydro and concluded on the basis of hot spring chemistry that no obvious high grade targets were in evidence. The recommendation was that Vancouver Island be reassessed periodically in light of continuing geologic mapping of the island by pure researchers and in light of state-of-the-art advances in geothermal exploration technology. At the present time, shifting of emphasis in exploration suggests that the coastal area around Tofino be re-examined.

Particular elements in the shifting of emphasis in exploration are the findings that the geochemistry of thermal springs is less definitive in British Columbia than was previously believed (see Appendix C for discussion) and an increased industry reliance on shallow temperature gradient wells.

The northern area on Vancouver Island lies near Port MacNeill. It is defined by erosion remnants of middle Tertiary volcanics and a cross cutting structure, the Brooks Peninsula Fault Zone. This area is one of two specifically examined in the field by us for the purpose of this study. It is our feeling that the volcanics are too old to contain any residual heat in subvolcanic intrusives; however, the structure and structural intersection nearby may harbour younger high-temperature rock bodies.

Queen Charlotte and Coastal Zones. Four other zones of high-temperature potential are shown in Drawing 3-7, on the Queen Charlotte Islands, at Lake Island, extending through Bella Coola, and between Terrace and the Nass River. All of these zones are elongate northwest. All are based on a combination of thermal springs, late Cenozoic volcanic rocks, and regional structural geology. All are inferred to have possibilities for high temperature geothermal resources.

Northwestern B.C. A very large irregular patterned area is shown in northwestern B.C. A high probability for high temperature geothermal resource is inferred in the vicinity of Mt. Edziza and other volcanos in the Stikine region. The remainder of the envelope of unknown probability derives from the distribution of volcanic rocks and such other tectonic elements as the King Salmon and Atlin faults.

Part of this area coincides with a Provincial Park and could be presumed to be closed to geothermal exploration or development.

Central Interior. Four other areas of unknown probability for high temperature resources are shown in the Interior, scattered from the west edge of Wells Gray Park north to the Sustut area. The selection of these regions is based on the occurrence of central volcanos, and their elongate shapes are derived from regional faults.

Low Temperature Resources. We suggest in Drawing 3-7 that the entire eastern margin of British Columbia has high or unknown potential for low-temperature geothermal resources. The high probability area in the south extends from the Arrow Lakes eastward to the Alberta border. It is based on the high concentration of deep circulating geothermal systems and thermal springs known in that region. Aspects of the shape of the area, an inverted "W", derive from regional structure.

A similar situation exists at and near the Liard River in northeastern British Columbia. Several thermal springs are present in British Columbia and across the border in the Yukon and Northwest Territories. Extending between the southern and northern areas is the entire Eastern Marginal Belt, which has similar geology and structure. We see no reason why it should not serve as a locus for the occurrence of additional deep circulation systems.

As mentioned in Section 3.5, the aquifers in the sedimentary basins east of the Rocky Mountain front are known to contain warm or hot brines.

3.7. Opinion on Resources Near B.C.

The terms of reference for this study requested comments on resources near B.C. with an eye toward potential development for meeting electrical or thermal loads within B.C. Geologic data suggests that such resources might exist, although at the present time they are neither discovered nor measured. Since development of any nearby resources would be inexorably linked to economic and jurisdictional factors, the following discussion will consider such factors briefly.

Washington. Mt. Baker (92A-1 on Drawings 3-2 and 3-3) is the northernmost of the chain of Cascade volcanos within the U.S. boundaries. The Sherman crater on Mt. Baker has been steaming for about five years. The geology and geothermal potential of Mt. Baker is probably very much like that of the Meager Creek system or Mt. Cayley.

No exploratory work has been done on or near Mt. Baker. There are two institutional barriers to the development of Mt. Baker for export power to British Columbia. For the past six years the U.S. Forest Service, an arm of the Department of Agriculture, has held up leasing on all Cascade volcanos in Washington and Oregon pending final establishment of environmental standards for exploratory activities. The private sector has been unable to proceed with any exploration, and the governmental organizations (U.S. Geological Survey, U.S. Department of Energy, and various state agencies) are limited to preliminary studies in geology and geophysics.

The second barrier to export of geothermal power from the United States is centered around the willingness of the American authorities and public to export energy to Canada. Stationary electric power in Washington state is projected to be in short supply within a decade, with or without the various nuclear power projects in progress. U.S. Federal Government approval for exports would be needed; and it could be expected that environmental impact hearings and approvals would be serious obstacles to a project aimed largely at exports.

Data on prospective geothermal resources elsewhere in Washington are reviewed most recently by Bloomquist et al (1980) and Schuster and Korosec (1980).

Yukon Territory. The distribution of late Cenozoic volcanic rocks near Whitehorse suggests that there is some possibility for a high temperature geothermal system in the southcentral Yukon. At the present time there is no provision for geothermal exploration and development in Yukon law. In 1980 the Yukon Territorial Government and the Land and Water Rights Branches of the Department of Indian Affairs and Northern Development considered geothermal development as related to a specific proposed project. However, no general decisions or guidelines have been forthcoming. The prospective geothermal area in the Yukon would be remote from all present electric demand in B.C., except for the community of Atlin.

Elsewhere. British Columbia is elsewhere bounded by the Northwest Territories, Alaska, Alberta, Montana and Idaho. There are several hot springs in the Nahanni River area of the Northwest Territories. These are considered to be most similar to the deep circulation systems of the Rocky Mountains, and they are 200 km from the B. C. border.

The Alaskan panhandle is an extension of geology and geothermal features in B.C. It is possible that exploration might take place in Alaska, subject to their extraordinarily complex land and mineral title situation, which includes Native land claims and U.S. Federal lands in the RARE-II program.

Southern Idaho is well-known for its geothermal resources; but there is no evidence for a substantial resource in Idaho or Montana nearer than a few hundred kilometers to the British Columbia border.

4.0 ECONOMIC MODEL FOR SYSTEM ELECTRIC GENERATING

4.0 ECONOMIC MODEL FOR SYSTEM ELECTRIC GENERATING

4.1. Introduction

The basis for an economic model for system-electric generation is developed in Appendix F.6., following the reviews of geothermal deposits, exploration, development, and parameters for energy conversion.

Three possibilities are considered for development:

1. Case 1, a dry steam field similar to the Geysers, California
2. Case 2, a hot-water field, capable of producing flashed steam, similar to the Roosevelt field, Utah
3. Case 3, a moderate temperature hot-water field similar to East Mesa, California.

The various characteristics of each noted in Appendix F are summarized in Table 4-1.

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Table 4-1 follows

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Several other assumptions are made:

1. The geothermal fluids are not chemically troublesome;
2. Wells are 1 500-2 000 m deep;
3. Liquid waste will be reinjected into the reservoir via disposal wells;

TABLE 4-1. Summary of Assumed and Calculated Characteristics of Three Prospective Economic Models (from Appendix F)

	Case 1 Dry Steam	Case 2 Hot Water	Case 3 Moderate Temp. Water
Reservoir			
- Temperature (°C)	240	270	180
Wellhead Conditions			
- Quality, % steam	100	20-35	0
- Available energy kJ/kg	880	305	150
Conversion			
- kg/kWh	8	30	60
Assumed flow per well			
- kg/h	90 000	180 000	180 000
Well Requirements for 50 MW plant			
- Total wells	7	17	40

4. The site is 75 km from an existing 230 kV transmission line;

5. An initial 50 MW(net) plant will be on-line in 1991 and will operate in the 30-year period through year 2020.

4.2. Cost Estimates

4.2.1. Capital Costs

Table 4-2 shows representative capital cost estimates for 50 MW plants under the three geothermal field conditions. These estimates are based on a review of published costs and cost estimates for U.S. projects.

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Table 4-2 follows

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Available cost estimates have been adjusted for inflation to mid-1980 dollars, and converted from U.S. to Canadian dollars at an exchange rate of C$ = US$ 0.85. While the adjustment is correct for imported equipment, labour and local equipment and materials might be obtained at lower costs. On the other hand, some allowance is desirable for a first-of-a-kind plant in B.C. The estimates include engineering and other indirect costs, but exclude interest during construction, which is handled separately in the economic analysis.

TABLE 4-2. Capital Cost Estimates, 50 MW (Net) Plants

	Mid-1980 dollars in millions		
	Case 1	Case 2	Case 3
Field Development			
Exploration	10	10	10
Wells	11	27	64
Gathering System	8	8	12
	29	45	86
Power Development			
Power Plant	30	38	60
Transmission	13	13	13
	43	51	73
Total, Field & Power - $ million	72	96	159
- $/kW	1 440	1 920	3 180

There would be some economies if a field could be developed for multiple units. On a cost per kW basis, there would be savings in exploration, transmission, and possibly economies of scale in unit sizes,by going to 100 MW units. Economies would also result from a learning curve effect. With a 400 MW development, the cost per kW might be at least 15 percent, and perhaps as much as 30 percent, lower than for the 50 MW plants shown in Table 4-2.

Parameters employed in the capital cost estimates are summarized below.

Escalation and Currency Exchange. The following adjustment factors have been used to convert U.S. cost estimated to 1980 Canadian dollars:

Base Year for U.S. Costs	Factor for 1980 Canadian $
1980	1.18
1979	1.32
1978	1.45
1977	1.55
1976	1.64

Exploration. An initial exploration budget of $10 000 000 is projected for a 50 MW project (Appendix E). For a larger development, we estimate an incremental exploration cost of

$5 000 000 per 50 MW of additional capacity.

Well Costs. The average well cost in the estimates is $1 600 000. This is consistent with estimates in Appendix E, and especially to igneous rock drilling.

Gathering System. The gathering system includes the transportation of steam, hot water or mixed steam and water to the power plant, and water from the plant to reinjection wells. Cassel et al (1979) indicates that mean gathering costs range between $160/kW and $225/kW depending on wellhead temperature, after adjustments to 1980 C$. The estimates in Table 4-2 are based on $160/kW for Cases 1 and 2 and $240/kW for Case 3.

Power Plants. Plant costs are estimated at $600/kW for dry steam (Case 1), $750/kW for single-flash (Case 2) and $1 200/kW for binary cycle (Case 3). (Appendix F describes the plant types.)

Reported costs and estimates for geothermal plants have shown rapid escalation during the 1970's. For example, the average plant cost for six 53 MW units completed at the Geysers in the 1971-73 period is reported to be about U.S. $6 000 000, or U.S. $120/kW, whereas the reported cost for Unit 15, completed in 1979, is U.S.

$315/kW (DiPippo, 1980).

The Unit 15 cost converts to about C$ 480/kW, but even this figure appears low: possibly engineering and overhead costs are not included. For example, conventional coal-fired steam plants in Alberta currently cost about $400/kW,exclusive of the boiler plant costs, at a unit size of 375 MW. Adjusted for the smaller scale, a 50 MW steam plant would be expected to cost about $600/kW--the estimate projected for Case 1.

Recent U.S. estimates for flash system steam plants indicate costs in the order of $750/kW when adjusted to 1980 C$. This cost appears correct in relation to the Case 1 estimate. Capital costs for binary plants are substantially higher than for conventional steam plants, as shown in two recent estimates:

1. Mitre (1979): $716/kW (1977 U.S.$) for 50 MW plant which converts to $1 110/kW (1980 C$);
2. Fluor (1979): $947/kW (1977 U.S.$) for 45 MW plant at Heber, including brine reinjection line, which converts to $1 470/kW (1980 C$).

Transmission Lines. Transmission line cost is estimated at $170 000/km for 75 km, the assumed length required, plus minor switching costs at an assumed substation.

4.2.2. Operating Costs

Most of the available data on operating costs are sketchy and not well defined concerning items included and excluded. The estimates shown in Table 4-3 are for operation, maintenance and administration, including allowances for operation labour and materials, maintenance labour and materials, payroll burden, insurance, municipal taxes, administration costs and interim replacements other than wells.

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Table 4-3 follows

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4.3. Economic Evaluation Using Utility Criteria

4.3.1. Basis for Evaluation

The costs of geothermal energy development for system electric use are totally speculative at this time, because there has not been sufficient exploration to define the useful resource. Thus, the purpose of this analysis is to assess the prospects for development given a successful exploration program. The three cases previously defined are

TABLE 4-3. Operating, Maintenance and Administration Costs, 50 MW(Net) Plants at an 80% Capacity Factor

		Mills/kWh		
	% Capital Cost	Case 1	Case 2	Case 3
50 MW Plants				
Field	3*	1.9	3.3	6.8
Plant	4	3.4	4.3	6.8
Transmission	2	0.6	0.6	0.6
Total:		5.9	8.2	14.2

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[*] Excluding exploration costs, which are considered sunk costs.

used in the analysis to show the range of costs that might be encountered; this provides a first cut at the type of resource that will be required to make development economically attractive.

The analysis is based on accepted utility company criteria for preliminary economic evaluation, to select the more promising alternatives for medium and long-term system requirements.

The first analysis presented shows comparative costs of geothermal, hydro and conventional thermal plants, based on the following conditions:

1. Geothermal Plants
    a. 50 MW unit located in the lower mainland, operating at 80 percent capacity factor
    b. Three alternative resource conditions as defined by Cases 1, 2 and 3
    c. Capital and operating costs from Tables 4-2 and 4-3
    d. Field and plant developed by a utility company
    e. Average well life 15 years
2. Hydro Plants
    a. Published capital and operating cost estimates for Peace River Site C,

adjusted to 1980$ (B.C. Hydro, 1979)

b. Comparative unit energy costs published by B.C. Hydro show Murphy Creek at slightly higher cost than Site C, and Stikine-Iskut and Liard River projects at slightly lower cost

3. Thermal Plants

a. Published capital and operating cost estimates for Hat Creek

b. Comparative unit energy costs show the cost of the East Kootenay thermal plant to be approximately equal to Hat Creek

4. Capacity Adjustments: For consistency with alternative hydro and thermal projects, an allowance has to be made for peaking capacity in conjunction with the geothermal plant to match a system load factor of 65 percent. A capital cost of $5 000 000 is charged to the geothermal plants to provide 11.4 MW of peaking capacity. Because of excess capacity in the system, relative to firm energy, this cost is not charged until the year 2 000.

4.3.2. Levelized Energy Costs

Levelized energy costs are calculated by discounting costs and energy production to present value at the same discount rate, and dividing the two to get mills/kWh. Capital and operating costs are expressed in constant 1980 dollars. The discount rates used in the analysis are expressed in "real" terms; i.e., excluding general inflation. In effect, the levelized energy cost can be considered as the revenue required to pay operating costs and recover the capital investment. Since it is levelized in 1980 dollars, it represents a revenue requirement that would increase in step with the general inflation rate.

A range of discount rates is used in the analysis because there are differing opinions on the cost of capital, the opportunity value of capital in the provincial economy, and whether costs or opportunity values are the appropriate measure for evaluating capital investments.

An accepted utility practice is to use real discount rates of 3, 6 and 10 percent in economic evaluations. The 6 percent discount rate represents an estimate of the real cost of capital for the mix of debt and equity used in project financing--with the equity component referenced to the value of their customers' capital. A 10 percent discount rate is recommended for project evaluation in the provincial "Benefit-Cost Guidelines" (within a range of 8 to 12 percent): this is based on an estimate of the average returns to the provincial economy on capital investment throughout manufacturing and other sectors. Where the 3 percent discount rate is used, it appears to be based on the real cost of a utility's debt (again excluding general inflation): this rate is relatively low, because sources of funds available to some utilities include borrowings from both provincial and federal pension funds at attractive rates.

Drawing 4-1 shows the assumed development

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Drawing 4-1 follows

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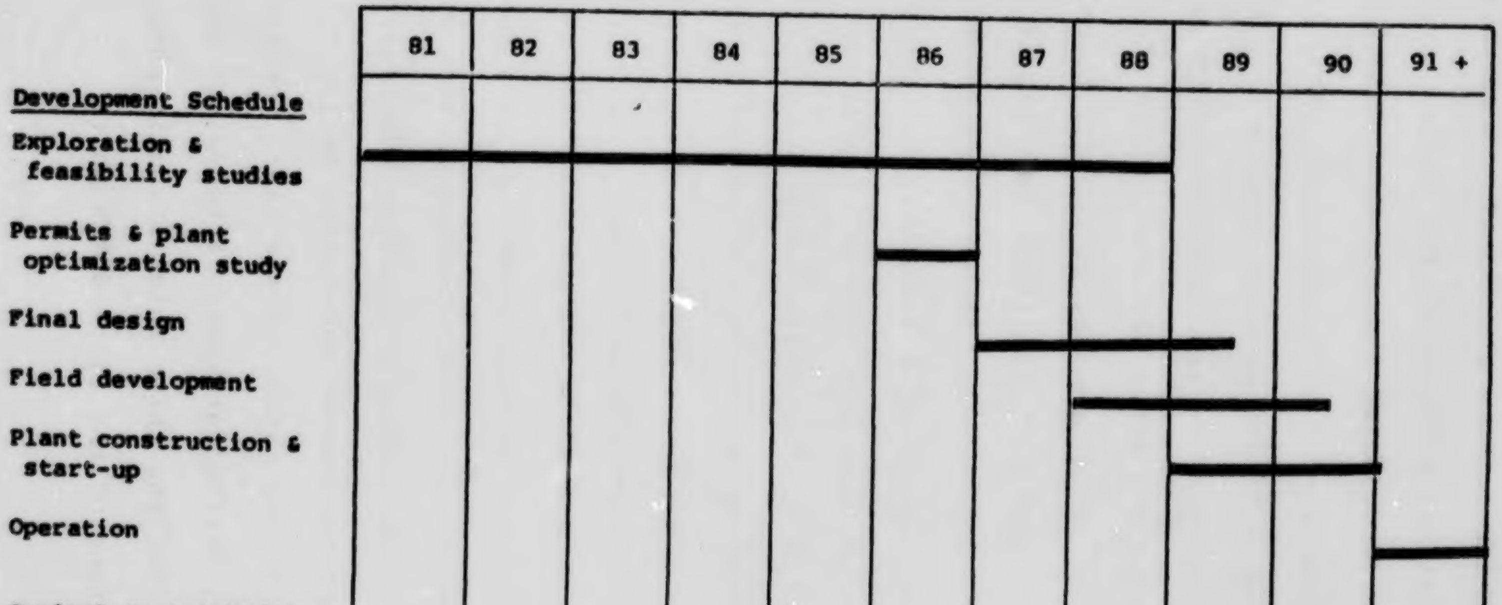
schedule for the initial 50 MW unit in a geothermal field. Generation would commence in 1991 with this schedule. (The schedule could be compressed if geothermal exploration is successful early in the 1980's). Depending on the nature of the field, additional units could be installed at yearly intervals. Capital cost schedules for the three cases are also shown, to commissioning of the first 50 MW unit.

DRAWING 4-1. Assumed Geothermal Development Schedules, First 50 MW Unit



Capital Cost Schedule - $ million (1980)

	81	82	83	84	85	86	87	88	89	90	Total
Case 1	0.5	0.5	1.0	2.0	2.0	2.5	2.5	11.6	22.6	26.8	72.0
Case 2	0.5	0.5	1.0	2.0	2.0	2.9	2.9	18.8	32.2	32.2	95.0
Case 3	0.5	0.5	1.0	2.0	2.0	4.0	4.0	37.4	57.4	50.2	159.0

Table 4-4 shows the levelized costs of

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Table 4-4 follows

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geothermal energy for the three cases. The levelized energy cost is based on 30 years' operation at 80 percent capacity factor.

The field costs include replacement of all production wells, with the costs spread over a 5-year period, operating years 12 to 17, inclusive. The cost of system peaking capacity, $5 000 000, is charged in the year 2 000.

Table 4-5 shows the comparative costs of

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Table 4-5 follows

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hydro, thermal and three classes of geothermal energy, all in terms of levelized energy costs at discount rates of 3, 6 and 10 percent. Hydro is the most capital-intensive of the alternative power sources; as a result, the hydro energy cost is most sensitive to discount rates. Thermal energy costs are least sensitive to discount rates; and geothermal energy costs are in between, although closer to thermal than hydro in sensitivity to

TABLE 4-4. Levelized Costs of Geothermal Energy, 50 MW Plant

1980 Present Values at Discount Rates Shown, 30 Years Operation

	Capital Costs - 10^6 $				Energy Generation 10^6 kWh	Levellized Capital Cost mills/kWh	OM&A mills/kWh	Total Energy Cost mills/kWh
	Field*	Plant & Trans.	Peaking Capacity	Total				
Case 1								
- 3%	27.8	32.7	2.8	63.3	5110	12.4	5.9	18.3
- 6%	21.1	25.1	1.6	47.8	2693	17.8	5.9	23.7
- 10%	15.3	17.8	0.7	33.8	1274	26.5	5.9	32.4
Case 2								
- 3%	43.2	38.8	2.8	84.8	5110	16.6	8.2	24.8
- 6%	32.1	29.8	1.6	63.5	2693	23.6	8.2	31.8
- 10%	22.9	21.2	0.7	44.8	1274	35.2	8.2	43.4
Case 3								
- 3%	82.5	55.7	2.8	141.0	5110	27.6	14.2	41.8
- 6%	60.5	42.8	1.6	104.9	2693	39.0	14.2	53.2
- 10%	42.1	30.6	0.7	73.4	1274	57.6	14.2	71.8

* Including replacement wells

TABLE 4-5. Comparative Costs of Alternative Power Sources (Levelized Cost, Mills/kWh (1980$))

Discount Rate (%)	Hydro (Site C)	Thermal (Hat Creek)	Geothermal (50 MW) Case 1	Case 2	Case 3
3	13	28	18	25	42
6	22	34	24	32	53
10	37	44	32	43	72

discount rate.* Table 4-5 strongly suggests that discount rate is an important parameter in project selection. Unfortunately, there is not universal agreement on a specific rate that should be used for project selection. Thus the full range of discount rates between 3 and 10 percent needs to be considered, with the following interpretation when comparing any two alternatives:

1. If one alternative is shown to have a lower cost over the entire range of discount rates, there is an economic preference for that alternative;
2. If there is a cross-over in economic preference within the range of discount rates, the alternatives are economically competitive and both require further consideration in subsequent evaluations.

A second factor that should be considered when interpreting results is possible changes in costs due to variations in the base parameters--for example, 400 MW field developments versus 50 MW plants, well flow rates, etc.

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*The sensitivity to discount rate is seen in the ratio of energy costs at 10 percent discount rate to the corresponding cost at 3 percent. These ratios are 2.85 for hydro, 1.57 for thermal and 1.71 to 1.78 for geothermal.

Given the above, the results in Table 4-5 are interpreted as follows:

1. A dry steam field (Case 1) on the lower mainland would be cost competitive with hydro power and lower cost than Hat Creek thermal. This interpretation holds even when the well requirements (and costs) are doubled, and is reinforced if the field could be developed to more than 50 MW. The location relative to the existing transmission network could alter the conclusion; i.e., a remote site might be non-competitive because of transmission costs.
2. A good hot water field (Case 2) would be about equal in cost to Hat Creek thermal and 1.2 to 1.9 times more costly than hydro power, with 50 MW development. At 400 MW development, the average energy cost would be in the order of 80 percent of the corresponding cost at 50 MW (20-35 mills/kWh depending on discount rate). Under this condition, or with more optimistic assumptions concerning well flow rates, geothermal energy is as economically attractive as the hydro model used.

3. A moderate temperature hot water field (Case 3) would provide high cost energy, not competitive with any of the other source models used; such developments, if undertaken, would be based on other than economic criteria.

5.0. ECONOMIC EVALUATION OF SMALL SCALE ELECTRICAL GENERATION

5.0. ECONOMIC EVALUATION OF SMALL SCALE ELECTRICAL GENERATION

5.1. Introduction

Within British Columbia there are a number of small electric generation installations using internal combustion engines as the prime movers. These installations are located at sites which are remote or where the electrical load is small and an extension of the main provincial grid cannot be economically justified. While the majority of these plants are operated by B.C. Hydro, a number are also privately owned and operated. Table 5-1 provides more specific information on a small sample of small generating plants currently operational in the province, for a total of 29 000 kW. Statistics Canada further reports a total of 142 000 kW of installed internal combustion generating capacity in the province.

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Table 5-1 follows

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The capital cost of internal combustion systems tends to represent a rather small proportion of annual operating costs. The main cost for small systems is for fuel, normally diesel oil. Diesel fuel costs commonly account for 50 to 80 percent of the annual operating expenses for diesel generating plants. During the 1978-1979 fiscal year total annual operating costs at

TABLE 5-1. Representative Diesel Generating Installations*

Location	Capacity (kW)	Operator
Atlin	1 200	B.C. Hydro
Bella Bella	1 800	B.C. Hydro
Bella Coola	1 150	B.C. Hydro
Massett	6 324	B.C. Hydro
McBride	1 800	B.C. Hydro
Sandspit	3 700	B.C. Hydro
Smithers	6 880	B.C. Hydro
Endako	2 250	Canex Placer Ltd.
Namu	1 460	B.C. Packers
Englewood Logging Div.	2 630	Canadian Forest Products
	29 194	

*The diesel generators operated by the Department of Indian and Northern Affairs to supply electricity to Native communities are not included in this table.

SOURCE: Statistics Canada, Catalogue 57-206.

a utility's installations ranged from 5.8 to 8.7¢ per kWh of output.

Since diesel fuel prices are tied to crude oil prices, it is almost certain that diesel generation will become more expensive in the future. The options with regard to fuel used in small plants is limited. Small-scale geothermal electrical generation is one possible alternative; small-scale hydro is another. The following discussion compares geothermal installations with small diesel plants.

In terms of their financing characteristics, geothermal facilities are more comparable with hydro-electric facilities than internal combustion installations--high initial capital costs can be expected to be offset by lower generating costs during the lifetime of the plant. In contrast with hydro, geothermal is subject to exploration risk (Appendices D and E).

5.2. Method of Analysis

The assumptions, variables and calculations performed are as follows:

1. A 1 800 kW diesel station is compared with a 1 500 kW geothermal station;
2. Although capacity factors depend on the nature of the load, as well as the type of plant, the difference in capacities is partly resolved by the high available capacity factors characteristic

of geothermal generating plants;

3. Estimates of capital costs, salvage value and costs of plant operators wages and salaries are developed for both plants. A range of three geothermal cost estimates is assumed, "high", "low" and "medium";

4. Assuming a plant operating life of 20 years and a variety of discount rates, the above costs are converted to equivalent annual costs stated in 1980 constant dollars;

5. In order to provide a basis for comparing diesel and geothermal generating costs over time, a 20-year diesel fuel price forecast is developed;

6. The current costs of generating electricity using diesel and geothermal prime movers are compared as $/kWh;

7. The sensitivity of the generation costs is tested by varying the plant capacity factors and the discount rates;

8. The period considered is 1981-2000;

9. The cost of diesel and geothermally generated electricity is compared on the basis of life cycle costs;

10. Several factors are not considered: income taxes, royalties or rentals on geothermal resources, public- or private-sector position of the operator,

interest cost during a lead time of exploration and development, and no provision for redrilling the well(s).

5.3. Diesel Plants

5.3.1. Capital Costs

Developing diesel plant capital and construction costs is a fairly straight forward task. The diesel installation in the 1 800 kW capacity range generally consists of three semi-trailer mounted 600 kW generating units. The cost estimates for the prime movers, generators and support equipment were obtained from B.C. Hydro and its suppliers. Since the site at which diesel generators are actually installed can be selected and placed close to the load or fuel transport depot, the civil engineering costs associated with site preparation and the creation of road access can be minimized. Capital cost estimates for an 1 800 kW diesel plant are presented in Table 5-2.

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Table 5-2 follows

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5.3.2. Operating and Maintenance Costs

The day-to-day operating and maintenance costs for most conventional small-scale electrical generating plants consist of fuel and the wages or

TABLE 5-2. Capital Costs: Small Scale (1 800 kW) Diesel Generating Station

Capital Costs

3 - 600 kW (2 400 volt) diesel generators; semi-trailer mounted @ $180 000/unit	$540 000
3 - sets switching gear @ $14 000/unit	42 000
fuel tank - 180 000 litre	144 000
Total Capital Costs:	$726 000

salaries paid to labour. For the purposes of this analysis, the personnel and maintenance expenditures for a diesel plant are assumed to remain constant at approximately $100 000 per year. The significant expense is diesel fuel, the consumption of which varies directly with diesel plant output. Over the long run, the cost of diesel fuel will be the major factor affecting the competitive stance of the geothermal alternative.

5.3.3. Diesel Fuel Price Forecast*

As the price of crude oil feedstocks rise, the price of refined petroleum products, such as gasoline and diesel fuel, will also increase. Depending on their magnitude, such price increases could have a significant impact on the cost of operating the diesel generating installations.

We have developed a forecast of diesel fuel prices which starts April, 1980, and spans the 20-year period, 1981-2000 (Table 5-3), in 1980

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Table 5-3 follows

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*Price forecasts were developed by Canadian Resourcecon Ltd. as part of separate national scale energy demand studies. The draft of this section was prepared in mid-1980.

TABLE 5-3. Fuel Price Forecast (in 1980 Canadian Dollars or cents as noted,

Year	Crude Oil $/bbl	Gasoline ¢/liter	Diesel ¢/liter
1980 (April)	16.80	22.22	17.99
1981	20.65	25.55	20.69
1982	23.20	27.78	22.49
1983	25.60	29.77	24.10
1984	27.50	31.33	25.37
1985	29.15	32.89	26.63
1986	31.55	34.89	28.24
1987	33.65	36.66	29.68
1988	35.70	38.22	30.94
1989	37.20	39.55	32.02
1990	38.45	40.66	32.92
1991	39.60	41.56	33.65
1992	40.78	42.66	34.54
1993	41.90	43.56	35.27
1994	43.05	44.44	35.98
1995	44.20	45.56	36.89
1996	45.10	46.22	37.42
1997	45.90	47.11	38.14
1998	46.80	47.78	38.68
1999	47.60	48.94	39.22
2000	48.50	49.11	39.76

Developed by: Canadian Resourcecon Ltd.

dollars. As is indicated, in 1980 dollars the price of diesel fuel is expected to double by 1994 and thereafter continue to increase by roughly 1.4 percent annually, through the end of the forecast period. These estimates are based on the crude oil and gasoline pricing scenarios also presented in the table.

The Canadian (Toronto city gate) price of crude oil forecast was developed using generally accepted pricing strategies. Specifically, it was assumed that the Canadian crude price will rise to 75 percent of the estimated world price by 1985 and 90 percent by 1990. For every $1/bbl increase in the price of crude oil, the 1980$ refinery price of gasoline is forecast to increase by 0.78¢/L. The pump (consumer) price of gasoline will be increased automatically by 9 percent of every refinery price increase, due to the federal sales tax which is calculated by 9 percent of the refinery product price; the pump price will therefore increase 0.85¢/L for every $1/bbl increase in the crude oil price (0.78¢/L x 1.09). It is assumed that over the forecast period the current (1980) gasoline-diesel fuel (consumer) price relationship will be maintained. With the exception of crude oil, all other costs (including provincial road taxes) are assumed to remain constant in real terms.

5.4. Geothermal Field and Plant Costs

5.4.1. Capital Costs

We assume that the field will be discovered as a result of one of the three scenarios given in Appendix E.3., at a cost outside the developer's control, ranging between $1 000 000 and $4 000 000. Characteristics of the resource and of the site may result in "low", "medium", or "high" costs of development (Table 5-4), largely independent of the cost of discovery.

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Table 5-4 follows

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For the higher cost models, it is assumed that well completions will be more expensive or additional wells will be needed; that separators will be needed; and that a higher level of civil engineering and construction effort will be required.

We assume installation of a modular 1 500 kW non-condensing (atmospheric discharge) plant (see Drawing F-1(4) on the first available one or two wells capable of supplying adequate steam or steam-water mixture.

TABLE 5-4. Installation Costs of 1 500 kW Non-Condensing Plant at Unknown Site, Excluding Transmission System

	Low Cost Case	Medium Cost Case	High Cost Case
Assumptions on System	High-grade system; Dry steam, no significant solids, say 50 tonnes/hr. and 1000 kpa at wellhead	Modest system: Hot water, low solids, mass flow 100 tonnes/hr. 50% flashes to steam at 700 kpa, dried to 500 kpa	Low-grade system: Hot water, silica-rich, 20% flashes to steam at 600 kpa, dried to 500 kpa 40 tonnes/hr
Assumptions on Site	No civil engineering difficulties at site; services and transport infrastructure in place	Moderate civil engineering tasks and upgrading of infrastructure	Some civil engineering problems to be solved; project has to supply own infrastructure
Costs (1980 dollars in thousands)			
Completing exploratory wells	65	130	195
Drilling and completing extra production wells	--	---	1,560
Flow testing and stimulation	26	84	195
Feasibility study	65	130	195
System design and plant selection	39	65	91
Purchase turbine-generator unit(s) - 3 @ $300,000/unit	900	900	900
Steam distribution separating, scrubbing system	26	65	130
Site preparation and buildings	39	78	195
Upgrading roads and infrastructure	--	130	650
Freight & installation of plant, pipe	26	39	65
TOTALS	$1,186	$1,621	$4,176

Combined exploration (Table F-3) and installation (Table 5-4) are given in Table 5-5.

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Table 5-5 follows

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Calculations are performed in Section 5.6 on three of the nine models: a "low-cost" case of about $2 000 000, a "medium" case of about $4 000 000, and a "high" case of about $9 000 000. The cost of transmission lines is not considered in the following comparison, but is noted in Section 5.7.

5.4.2. Operating Costs

The geothermal operating costs are assumed to be the same as the non-fuel diesel operating costs, viz. $100 000 per year for operating personnel, maintenance, overhead and administration.

5.5. Economic Assumptions

Several variables have an important influence on the relative cost of producing electricity by either geothermal or conventional means:

1. the capital cost and source of capital
2. the discount or rate of return
3. the average capacity at which the plant is operated
4. the cost of fuel
5. the life of the project.

TABLE 5-5. Range of Costs for a Small Geothermal Electric Plant (1 500 kW) Based on Sums of Cost Models for Exploration (from Table E-3) and Installation (from Table 5-4)

1980 Dollars in Thousands

Installation Cost Model		Exploration Cost Model		
		Low Cost	Medium Cost	High Cost
		$ 955	$ 2 073	$ 4 836
	Low $1 186	2 141	3 259	6 022
	Med 1 621	2 576	3 694	6 457
	High 4 176	5 131	6 249	9 012

5.5.1. Capital Costs

For the purposes of the analysis, capital expenditures are assumed to consist of 100 percent debt. These are converted to equivalent annual costs incurred over the life of the project and are then added to the annual operating costs. All costs are stated in 1980 constant dollars. This facilitates comparison between projects without reference to a specific point in time. The equivalent annual cost method implies that capital costs are recovered by annual revenues that increase at the general inflation rate. While this is not necessarily the way capital costs are recovered in practice, the methodology is useful for comparing different projects capable of performing the same task.

5.5.2. Discount Rate

For the purposes of this analysis,discount rates of 3, 6 and 12 percent were chosen. The 3 and 6 percent rates are consistent with discount rates used by certain utilities for evaluating projects. The 12 percent rate is more appropriate for private investment analysis. The lower discount rates tend to favour projects with high capital and low operating costs. For the high rates, the opposite is true.

The choice of discount rate, or the minimum acceptable rate of return, theoretically reflects the opportunity cost of employing capital in one project as opposed to another. Traditionally, the discount rate applied to publicly financed projects has been substantially below the rate considered acceptable by the private sector. The rationale is that risks shared by society are less onerous than risks borne by the individual private investor. Furthermore, in the case of Crown corporations, such as a utility which might consider installation of a small generating plant, their non-taxable status and the fact that lenders include provincial- or federal-trusteed funds, such as pension plans, also contribute to low discount rates. Trusteed funds traditionally charge lower interest rates.

5.5.3. Plant Capacity Factors

The plant capacity factor is the ratio of average power produced during a year to its maximum generating capacity. For a given plant, the capacity at which it is likely to be operated is a function of its standby capacity, the number and size of generating units at the plant, and the annual load factor. In practice, forced outages and scheduled maintenance shutdowns rarely permit capacity factors in excess of 80 percent to be achieved.

The diesel generating stations in British Columbia serve base and peak loads in varying proportions. Typical capacity factors are 25 to 50 percent. The low capacity factors are partly by design. The load serviced is residential, characterized by large variations between peak and base demand. Industrial loads, especially for round-the-clock operations, tend to be more constant, and therefore permit the electrical generating installations servicing them to achieve a higher capacity factor.

Geothermal wells, reviewed in Appendix F, are best maintained by leaving them open once they are flowing. Even when the generator is shut down for a period the wells are generally vented into the atmosphere. The larger geothermal fields lend themselves to high-capacity factor operation, commonly 80 percent or greater. Small one- or two-well systems might be expected to be less predictable in their capabilities.

5.5.4. Fuel Cost

The costs of fuel are considered to be of significance only in terms of the electricity produced by diesel generation. Although only one fuel price forecast is developed, the fact that the prices given are in 1980 constant dollars facilitates the comparison of diesel and geothermal generation costs over a range of diesel fuel prices.

The cost of geothermal "fuel" clearly consists mainly of amortizing the preproduction capital cost.

5.5.5. Project Life

Both installations are assumed to have an operating life of 20 years. Operators generally consider internal combustion equipment to be obsolete and due for replacement after 20 years of operation.

For a 20-year period, it is unlikely that a hydrothermal system would deplete (undergo an overdraft of heat or fluid such as to lose its commercial quality) significantly at the low rate of utilization considered here. The most likely adverse event would be precipitation of solids in the well, near the points of exit from the reservoir, or in pipes, separators or turbines.

5.6. Comparison of Alternatives

Tables 5-6 and 5-7 provide a summary comparison of the costs of producing electricity with

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Tables 5-6 and 5-7 follow

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TABLE 5-6. Calculation of Diesel Generation Costs (1980 dollars)

Assumptions

Debt/equity :	100% debt
Discount rate :	6 percent
Project life :	20 years
Salvage value :	10% of depreciable assets
Capacity factor :	80% (12.6 Gwh output/annum)
Fuel costs :	(1980) 17.99¢ litre
Heat rate :	11,811 Btu/kWh (3.1 kWh/litre)

Capital Expenditures

3 - 600 kw (2400 volt) generating units @ $180,000/unit	$ 540,000
3 sets switching gear @ $14,000/unit	42,000
1 - 180,000 litre fuel tank	144,000
Total Capital Expenditures	$ 726,000
Annual Labour Costs	$ 100,000

Equivalent Annual Fixed Costs

Capital Costs	$ 63,300
Salvage value (10% of total capital expenditure)	(1965)
Labour	100,000
Equivalent Annual Variable Costs	
Fuel 4,069,161 litres @ 17.99¢/litre	732,040
Total Equivalent Annual Costs	$893,375

Electricity Production Costs (¢/kWh)

12.6 Gwh @ $893,375 = $7.08¢/kWh

TABLE 5-7. Calculation of Geothermal Generation Costs (Medium Cost Case) (1980 dollars)

Assumptions

Debt/equity : 100% debt
Discount rate : 6 percent
Project life : 20 years
Salvage value : 10% of depreciable assets
Capacity factor : 80% (10.5 Gwh output/annum)
Fuel costs : N.A.
Heat rate : N.A.

Capital Expenditures

Exploration and discovery wells	$2,073,500
plant installation costs	1,621,500
Total Capital Expenditures	$3,695,000
Annual Labour Costs	$ 100,000

Equivalent Annual Fixed Costs

Capital costs	
-exploration and discovery	$180,809
-plant installation	141,395
Salvage value*	(2,836)
Labour	100,000
Equivalent Annual Variable Costs	
Fuel	NA
Total Equivalent Annual Costs	$419,368

Electricity Production Costs (¢/kWh)

10.5 Gwh @ $419,368 = 3.99¢/kWh

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* Depreciable assets assumed to consist of turbine-generator units, steam distribution separating scrubbing system and buildings

diesel and geothermal generating stations assuming a 6 percent rate of return and similar debt/equity ratios and capacity factors. The relative importance of fixed (mainly capital) and variable (fuel) costs in terms of their contribution to geothermal and diesel generating costs can be seen.

Drawing 5-1 represents the "highest" and "lowest" cost diesel power on a yearly basis to year 2000. Varying only the capacity factor and the discount rate (from 80 percent and 3 percent respectively for the least cost scenario, to 50 percent and 12 percent for the highest cost scenario) increases total generating costs by about 1.5¢/kWh or 19 percent. This holds for each of the 20 years of operation, as fuel cost increases and power cost progressively doubles.

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Drawing 5-1 follows

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For the medium cost geothermal plant varying between high capacity-low discount rate and low capacity-high discount rate (Drawing 5-2) results

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Drawing 5-2 follows

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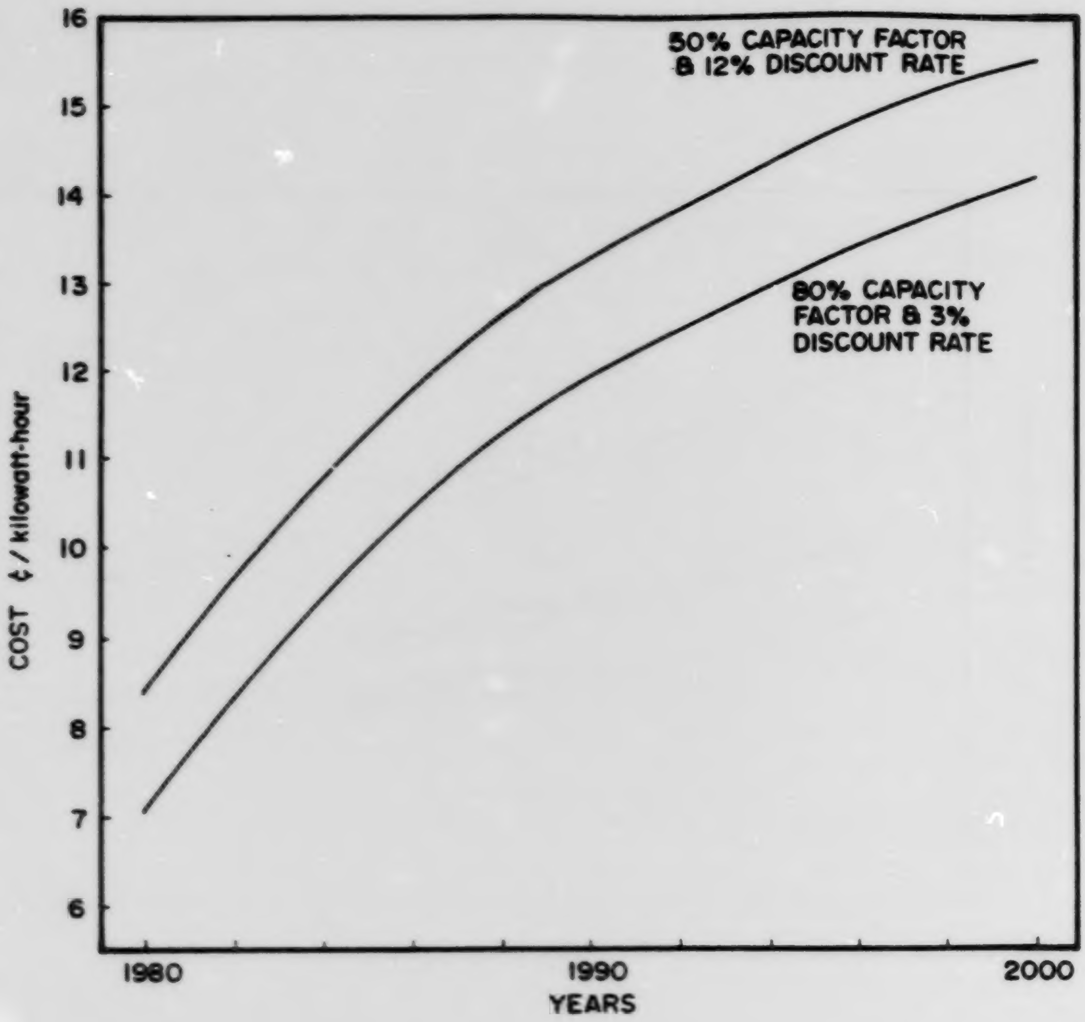
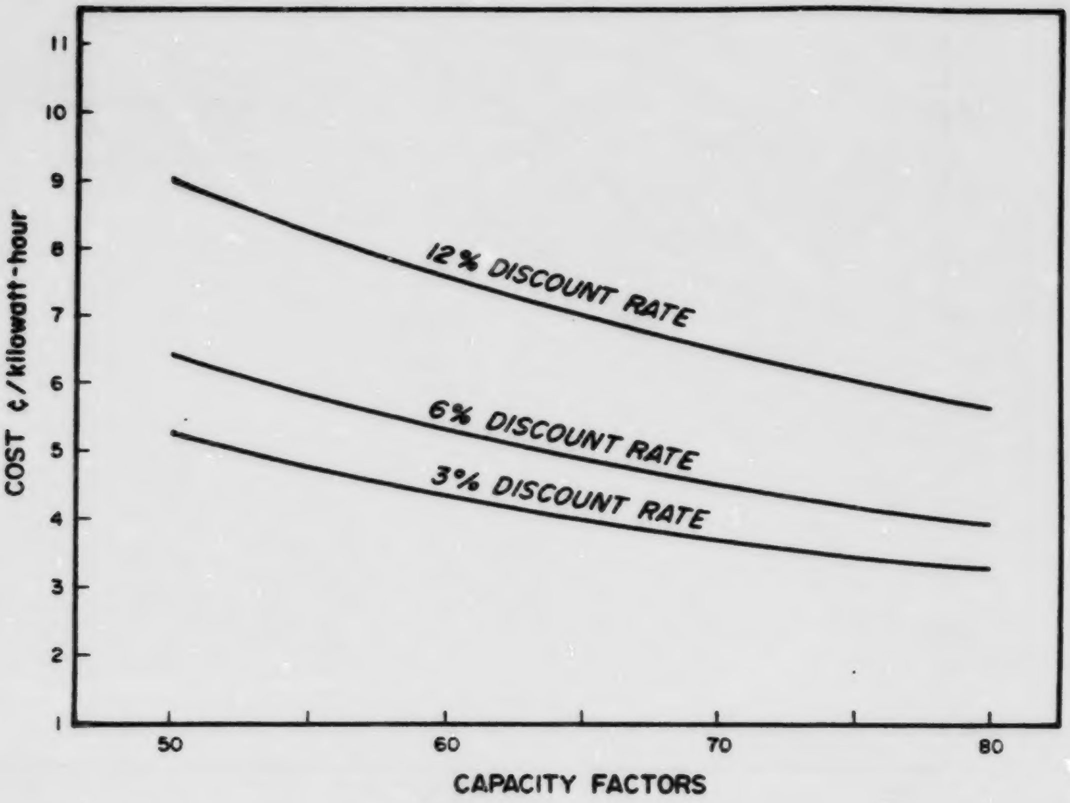


DRAWING 5-1

DIESEL GENERATING COSTS

Highest and lowest projected cost scenarios

SOURCE: Canadian Resourcecon Limited



DRAWING 5-2

VARIATIONS OF MEDIUM-COST 1500 kW GEOTHERMAL ENERGY AS A FUNCTION OF CAPACITY FACTOR in a differential of about 6¢/kWh, or 175 percent, which is constant regardless of the year.

A combination of these two representations is given in Drawing 5-3, with the addition

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Drawing 5-3 follows

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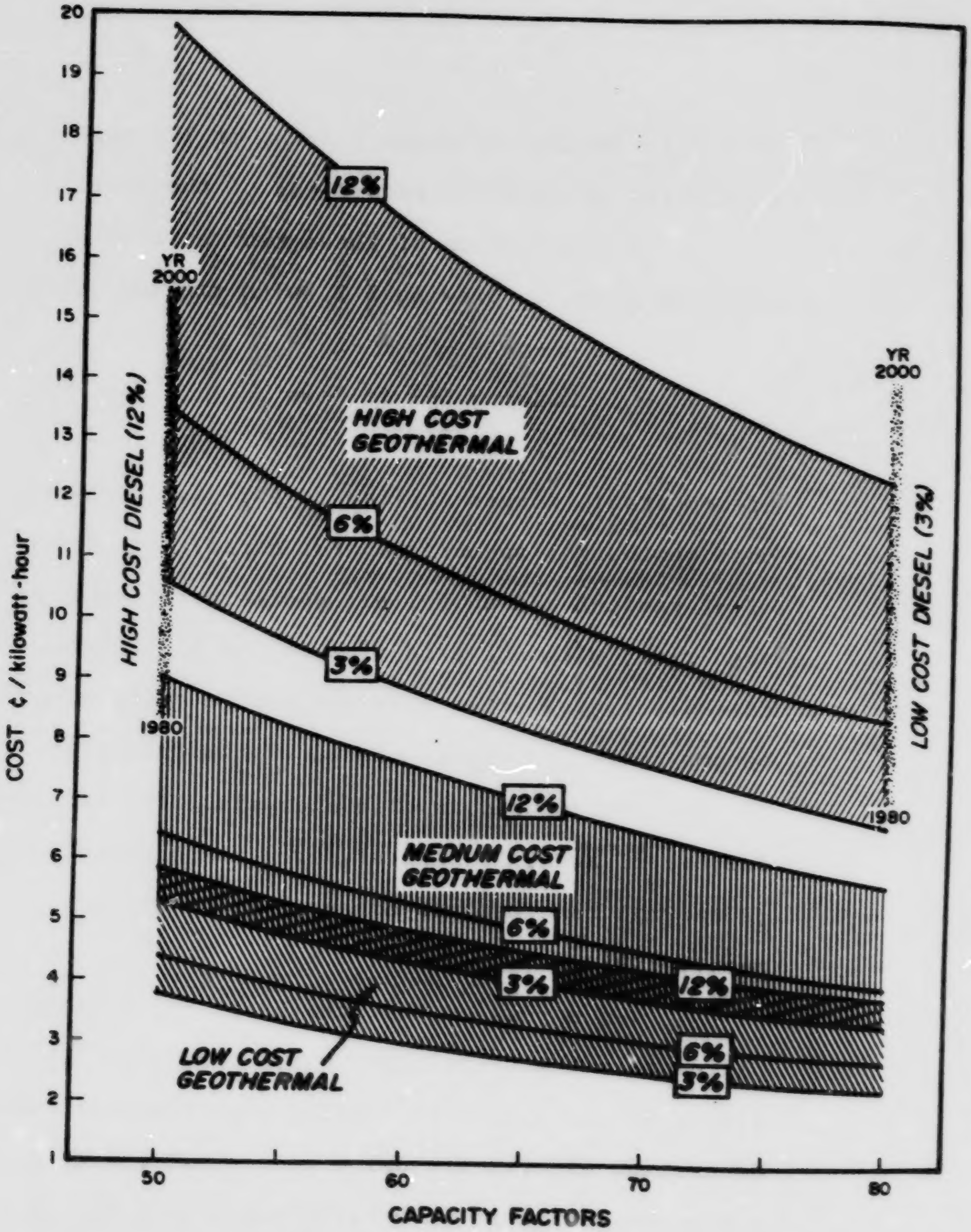
of comparable curves for the lowest- and highest-cost geothermal scenarios. For capacity factors of 50 percent and above, all geothermal operating scenarios, with the exception of the high cost case discounted at 12 percent, can be expected to become competitive with diesel plants during the 20-year period used in this analysis. For capacity factors of about 70 percent, even the highest cost geothermal case becomes competitive by approximately 1995.

We emphasize that the basis for these comparisons is the diesel fuel price forecast. If diesel prices rise more rapidly than forecast, then generating electricity using geothermal energy becomes attractive at an earlier point in time; if diesel prices rise more slowly, or if the geothermal development and installation cost estimates used in this study are too optimistic, then the opposite is true.



DRAWING 5-3

COMPARISON OF ENERGY FROM DIESEL AND SMALL GEOTHERMAL PLANTS AT DIFFERENT CAPACITY FACTORS AND DISCOUNT RATES

5.7. Comments

An alternate method of comparison to annual costs is life-cycle costs; in this case the average over 20 years. The average price of diesel-generated power is 11.6¢/kWh (for the low-cost model) or 12.9¢/kWh (for the high-cost model).

In the case of small-scale geothermal energy projects, the preponderance of fixed cost components in the annualized capital and operating budget means that life-cycle costs do not differ from the annual cost incurred during a specified year in the life of the project.

Geothermal power, if exploration is successful within the costs estimated, appears capable of power at a lower cost than diesel on the life-cycle basis for the years 1981-2000, as well as on the annualized basis discussed.

All considerations of the economics of small-scale geothermal power are predicated on:

1. the existence of a geothermal resource close to the load, and
2. the success and cost of exploration.

The many factors bearing on location, risk, success and reward are discussed in Appendices C (location), D (exploration technology), E (costs, and in particular, Appendix E.3.), and F (parameters for conversion).

Successful development of a small-scale geothermal plant might have some secondary economic benefits: viz. direct heating use of waste of surplus fluid, or continued exploration and development of the resource for broader system-electric applications, and so forth.

Finally, it should be pointed out that geothermal energy is only one alternative to generating electricity with diesel plants. As the price of diesel fuel increases and technology improves, generating electricity by wind, solar, or small-scale hydro plants will also become more viable.

6.0 ECONOMIC EVALUATION OF GEOTHERMAL SPACE HEATING

6.0 Economic Evaluation of Geothermal Space Heating

6.1. Introduction

As in the previous analyses of the economics of system and small-scale generating (Sections 4.0 and 5.0), this analysis sets up a reasonable model. In this case we use a community of 3 000 population. The same caveat applies: the application is subject to the occurrence and proximity of the geothermal resource (Section 3.0); properties of the fluid, including heat content and absence of troublesome dissolved solids (Appendix C); successful exploration and development at an appropriate cost (Appendices D and E), and various factors which affect direct use (Appendix G).

As the cost of the conventional energy forms used for space heating escalates, interest in alternative forms of energy can be expected to increase. Among these alternatives is geothermal energy. The development of geothermal wells by private homeowners to serve the space heating needs of one or two households remains a possibility. It is also likely that geothermal heating systems will be operated on a basis resembling that of the natural gas and water utilities or existing central district heating systems.

The relative costs of residential space heating, using geothermal energy and a variety of conventional energy forms and heating systems are examined for a hypothetical community.

The evaluation comprises the following steps:

1. A model of a community or heating district is developed;
2. Using community building structure data and climatic information, the community heat load is calculated and energy requirements are estimated;
3. Capital and operating cost estimates for various configurations of geothermal and conventional energy systems are developed;
4. Standard financial analysis techniques are utilized to compare geothermal and conventional fuel heating costs.

6.2. Community Reference Case

The model community providing the basis for the evaluation consists of 1 000 households, comprising 700 single-family detached dwellings, and 300 apartment units in blocks of 24 suites each. The stock of housing is considered to be sufficient to meet the needs of a population of approximately 3 000 (a figure commonly associated with remote, resource based communities). In addition to the residential sector, the community is assumed to have approximately 100 commercial outlets. A more detailed description of the community model and the relevant engineering design parameters for the heating systems is offered in Table 6-1.

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Table 6-1 follows

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The design heat load calculated in Table 6-1 determines the capacity which must be installed if a heating system is to be capable of maintaining adequate room temperatures during the coldest day of the year; ultimately, it also determines capital expenditures. Since a system is likely to operate at its peak capacity only a few days per year, from the perspective of calculating operating costs, the more relevant factor is the annual heat load. The annual heat load calculations by sector are summarized in Table 6-2.

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Table 6-2 follows

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6.3 Space Heating Systems

6.3.1. Conventional Heating

In British Columbia the space heating systems most widely used in residential and commercial buildings include forced air, hydronic, and electric resistance baseboard systems. The type of system installed, and the choice of heating energy, is determined by the structural characteristics of the building to be heated and the availability and cost of

TABLE 6-1. Community Reference Case

Population : 3000
Households : 1000
Housing stock : 700 single detached and 300 apartment suites @ 24 suites per block (3 storey walkups)
Commercial outlets : 100

Engineering Design Parameters
Design Operating Conditions

Degree days : 4630 degree days below 18°C with a temperature drop of 40°C (Terrace, B.C.)

Inside Design Temperature : $T = 21^{\circ}C$

Outside Degree Temperature : $T_o = -22^{\circ}C$

Design Temperature Difference : $DT = T - T_o = 43^{\circ}C$

Annual Degree Days : ADD = Degree heating days per year = 4630

Annual Heat Load Factor : $F = ADD/365\ (T-T_o)$

Annual Operating Hours : $OH = F \times 365 \times 24$

Winter Design Heat Load[(a)]

Single dwellings : 47.74 MJ/hr.

3 Storey apartment (24 suites) : 275.37 MJ/hr.

Total residential heat load:

Single family dwellings : 700 x 47.74 = 33418 MJ/hr.
Apartments : 300/24 x 275.37 = 3442 MJ/hr.

Commercial sector : 1 commercial account per 10 residential accounts with each commercial account experiencing eight times the heat load of a residential account; .8 x (33418 + 3442) = 29488 MJ/hr.

Total Community Design Heat Load : 66,348 MJ/hr.

(a) The heat load calculations are based on dwelling specifications presented in the B.C. Energy Commission's Residential Home Heating Study, 1979.

TABLE 6-2. Annual Heat Loads

Design Temperature Difference : $43^{\circ}C$

Annual Degree Days : 4630

Annual Heat Load Factor : $\frac{4630}{365 \times 43} = .29$

Annual Operating Hours : $.29 \times 24 \times 365 = 2540$ hrs.

Residential Sector

Single Detached Dwellings (700 units) Annual heat load	2540 hrs. x 33418 MJ/hr. =	84.9×10^3 GJ
Apartments (300 suites) Annual heat load	2540 hrs. x 3442 MJ/hr. =	8.74×10^3 GJ
Commercial Sector (100 accounts) Annual heat load	$(8.49 \times 10^7 + 8.74 \times 10^6) \times .8 =$	74.9×10^3 GJ
Total Annual Heat Load		168.5×10^3 GJ

various forms of energy. In areas serviced by natural gas, the majority of single-family dwellings rely on gas-fired forced air systems for their space heating needs. In non-gas areas, electrical resistance and electric or oil fired forced air furnaces fulfill this role. Apartments and commercial buildings typically employ electric resistance or oil or gas-fired hydronic systems.

With the rapid rise in petroleum prices, the popularity of oil as a heating fuel has steadily diminished in favour of electricity and natural gas. Traditionally, the capital cost of electrical resistance heating has been well below that of competing systems, while operating costs have been substantially higher. As the cost of oil rises relative to electricity the operating cost disadvantage of electrical heating will become less and less significant. A greater number of electrical heating systems can be expected in areas where natural gas is not available.

Conventional heating alternatives assumed to be available to single family dwellings include natural gas, oil and electrical forced air systems and electrical resistance heating. Apartments are assumed to be heated by either natural gas hydronic or electrical resistance systems. For the commercial sector, no direct comparison of geothermal and conventional systems is attempted.

The capital costs of the infrastructure required to supply the community with natural gas and electricity are assumed to be accounted for in the consumer price of the respective energy forms. As such, this capital cost component is included in the annual operating (energy) cost estimates.

6.3.2. Geothermal Space Heating

Like natural gas or electric heating, a geothermal system comprises two major components, the energy supply and distribution network and the home heating plant. The distribution infrastructure for a geothermal heating system is comparable to that for a natural gas utility. From the wellhead, the thermal fluid is pumped through an insulated transmission pipeline and a series of distribution mains and service runouts to the individual heating customers. If, as is assumed in this analysis, the thermal fluid is relatively free of chemical constituents which may have a deleterious impact on the heating system's components, then the thermal fluid can be circulated directly through these components. When direct circulation is not feasible, a water-water heat exchanger is installed at the wellhead. This can add substantially to the system's capital costs.

The design capacity of a geothermal system is determined by the heat content of the thermal fluid and by the system's peak load. Space heating systems are generally characterized by low load factors. In the case of capital intensive systems, such as geothermal heating, it is often more economical to design the system for a base load, and to meet peak requirements with an auxiliary heating mode.

For the purposes of this study two geothermal configurations were designed. One is based on the assumption that 100 percent of the heating load will be met with geothermal fluid temperatures of approximately 75°C. The other assumes that only 70 percent of the peak load will be met geothermally. In the latter case, peak requirements are assumed to be met by employing a booster boiler to raise fluid temperatures to approximately 87°C. By reducing the geothermal system's design capacity, capital expenditures for wells, transmission pipeline, and distribution mains are lowered; these cost savings are offset in part by a booster boiler's capital and operating costs.

Two types of geothermal heating plants are most common: in single family dwellings, forced air is generally used. The conventional electric heating coils or fossil fuel burners are replaced with a geothermally heated hot water fin coil. Air blown through the coil is distributed through ductwork, as with conventional systems. Hot water coil design is based on the heat load, and the temperature and flow rate of the geothermal water. Appropriate coil design, air handling capacity and water flow allow forced air systems to be used with average water temperatures as low as 50°C.

The second common system is generally used in apartment buildings. Hydronic systems pump hot water through a baseboard convector. Where high heat loads are encountered due to severe climatic conditions, or to poor energy efficiency in building design and construction, heat source (thermal fluid) temperatures below 60°C are unlikely to be practical. Convector length in baseboard convection systems is influenced by the average water temperature in the system. Heating effect is determined from the temperature drop across the system component and the flow rate, and is specified as megajoules per hour per meter (MJ/h-m), at a specific flow rate and temperature drop. Increasing the length of a convector will result in a proportional increase in heating effect only if the flow is increased to maintain the average water temperature. An increase in heating effect can be obtained by increasing the water flow rate. This in turn reduces the temperature drop through the system and increases the temperature difference between the heating component and the space to be heated, thus creating greater heat flow per unit time between them. Flow control is used to regulate the heating effect of hydronic systems.

The principal differences between conventional and geothermal hydronic space heating systems are that the geothermal system has no conventional boiler, uses a lower temperature working fluid and, where necessary, includes a heat exchanger to isolate contaminated thermal fluids from the heating system's working parts.

An alternative to the two common geothermal heating systems is the radiant floor system. It consists of hot water coils embedded in a floor, which in turn act as a heat radiator. Although this system is capable of operating with low fluid temperatures, as low as 38°C (Engen, 1978), its capital cost is almost double that of the forced air of hydronic systems. It is not considered in this evaluation.

Retrofitting. In addition to considering new residential and commercial buildings, the analysis considers retrofitting existing buildings with geothermal components. Retrofitting forced air systems presents few problems. Usually the conventional heating capability is retained to meet the peak load and as a backup. Geothermal capability is achieved by modifying the existing furnace to accept a hot water coil; typically conversion retains existing ductwork and piping.

Retrofitting buildings with hydronic heating systems usually requires the addition of more fin coil units to compensate for the lower geothermal operating temperatures. Due to the limited availability of wall space in any given living area, this approach has practical and aesthetic limitations.

Retrofitting structures which are currently heated with electric resistance units is also possible. Technical problems of working in confined spaces and the probable need to make structural alterations, however, suggest that the costs of retrofitting would exceed those of new installations by a large margin.

6.4. Heating System Costs

6.4.1. Capital and Installation

Estimating costs for home heating plants is a straightforward process; accumulated experience with conventional heating systems indicates that capital and installation costs can be estimated with a high degree of accuracy. Most of the components used in a geothermal heating plant are off-the-shelf items, with well established design and installation costs.

Deriving preliminary estimates for the cost of a geothermal supply and distribution system is much more problematic. The qualities and location of the geothermal resource have to be known before a precise estimate can be made. In this analysis several assumptions are made about the geothermal field.

It is assumed that the geothermal fluids are free of contaminants. The temperature of the fluid on expulsion from the heating system is low, so disposal of the effluent via the residential sewage system is assumed to be acceptable. In cases where effluent is too contaminated to permit direct surface discharge, costs would be incurred for reinjection wells, transmission pipe, or evaporation ponds. A disposal system can approach 50 percent of the capital cost of production wells (Engen, 1978).

In the following tables capital cost estimates for the various conventional and geothermal heating system components are presented. The estimates for the geothermal system encompass all components, from the wells to the home heating plant. For conventional units only the capital costs of the home heating plants are presented.

Table 6-3 summarizes the cost of develop-

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Table 5-3 follows

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ing a geothermal field with a capacity sufficient to meet 100 percent and 70 percent of the model community's peak load. The estimates assume the development of medium quality wells having a resource temperature of 75°C yielding 5 760 MJ/h/well (see Appendix E). The well development costs are based on an estimate of approximately \$28 per MJ/h (or \$100/kWt). All costs are in 1980 dollars.

Table 6-4 summarizes the capital and in-

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Table 6-4 follows

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stallation cost of the geothermal transmission and distribution system assuming 100 percent and 70 percent capacity ratings. The transmission component costs are based on a pipeline length of 5 km. Distribution main requirements assume a length of 6.22 meters per residential account (1 000) with service

TABLE. 6-3. Geothermal Well Costs

100% Geothermal Peaking Capacity : 66,000 MJ/hr.

Drilling Costs : 12 wells, 5760 MJ/hr./well

$27.78/MJ x 5760 x 12 = $1,920,000

70% Geothermal Peaking Capacity : 46,200 MJ/hr.

Drilling Costs: 8 wells, 5760 MJ/hr./well

$27.78/MJ x 5760 x 8 = $1,280,000

Note: 5 760 MJ/hr = 1 600 kWt, or a median range for a hot water well. See Appendices D and E for treatment of wells and costs.

TABLE 6.4. Geothermal Transmission and Distribution System Installation Costs (1980$)

System Type	100% Geothermal	70% Geothermal
Transmission Pipeline: 5 km @ $387,814/km - 100% Geothermal @ $339,337/km - 70% Geothermal	$1,939,070	$1,696,685
Distribution System		
Mains: 100% Geothermal 1000 x 6.22 metres @ $152/metre	945,440	
70% Geothermal 1000 x 6.22 metres @ $133/metre		827,260
Booster Boiler - 70% Geothermal		120,000
Service Connections: 1000 x 21.34 metres @ $154.90/metre	1,171,566	1,171,566
Pumps: @ $8600/unit	60,200	43,000
Excavation and Backfill[(a)]		
Transmission Pipeline: 5000 metres @ $9.85/metre	49,250	49,250
Distribution System:		
27560 metres @ $4.40/metre	135,044	135,044
Total Installation Costs	$4,300,570	$4,042,805

(a) These estimates should be viewed with considerable caution. Excavation costs vary according to the terrain which must be traversed; in many cases blasting as well as special environmental protection measures will be necessary during the period of the pipeline's construction. With respect to the distribution system, the cost of repairs to roadways and sidewalks are not included; such costs would be incurred in most retrofit cases.

connections of 21.34 meters per account. The latter estimates are based on water and gas utility experience. They include an allowance for the 100 commercial accounts in the reference community.

Adding and comparing well development and distribution system costs for the capacity ratings considered indicates the capital cost of the 70 percent capacity system is almost $900 000 below that of the 100 percent geothermal system.

Tables 6-5 and 6-6 document the installed capital costs of the geothermal and conventional energy heating plants compared in this study. The cost estimates are based on contractor experience and "Building Construction Cost Data, 1980". These estimates include an appropriate allowance for overhead and profits.

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Tables 6-5 and 6-6 follow

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Forced air geothermal plant costs are comparable with those of natural gas and below those of oil furnaces. Varying the geothermal design capacity does not alter these costs. The cost of the natural gas hydronic system installed in an

TABLE 6-5. Single Family Detached Heating Systems Installed Costs (1980$)

System Type	Geothermal	Natural Gas	Forced Air Electric	Oil	Resistance Electric
Duct Work	$2,500	$2,500	$2,500	$2,500	N.A.
Furnace, Assoc. Equip.		1,050	690	2,070	1,700
Hot Water from Coil Unit	775				N.A.
Controls	300	———	———	———	———
Total	$3,575	$3,550	$3,190	$4,570	$1,700
For retrofitting of forced air systems to geothermal heating:					
Hot water coil and controls and piping inside house				$ 700 (a)	

(a) Retrofit costs for the hot water coil etc. are lower because they are not the industrial quality machines which are normally installed in new construction.

TABLE 6-6. 24 Unit Apartment Block Heating Systems - Installed Costs (1980$)

System Type	Geothermal	Natural Gas	Electric Resistance
Convectors, piping	$26,700	$26,700	N.A.
Controls	3,600	3,600	N.A.
Vent 2,500	2,500	N.A.	
Boiler, controls and circulation pump	N.A.	18,270	N.A.
Baseboard heaters	———	———	20,160
Total Costs	$32,800	$48,570	$20,160
Retrofitting Costs: Addition of convection fins @ $500/unit	$12,000		

apartment block is above that of the geothermal system only because of the need for a boiler and associated equipment. If the geothermal operating temperatures were to be reduced, however, each apartment would require additional convectors and the costs would rise accordingly.

6.4.2. Maintenance

Annual maintenance cost estimates for the components of the heating systems considered in this evaluation are presented in Table 6-7. The

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Table 6-7 follows

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estimates covering the heating systems installed in single family homes are based on operator experience. For larger components specific maintenance costs are difficult to calculate and it is accepted practice to assume them to be a fraction of the capital cost of the component. Estimates in the 2-3 percent range are considered to be acceptable.

6.4.3. Operating Costs

Operating costs, as treated here, refer entirely to energy or fuel costs; labour-related expenditures are assumed to be included in maintenance cost estimates.

TABLE 6-7. Annual Maintenance Costs

Component	Annual Maintenance Costs
Geothermal Wells, Transmission and Distribution System:	
calculated @ 2.5% of capital and installation costs	
-100% geothermal	$107,514
- 70% geothermal	101,070
Home Heating Plants /Single Family Residence:	
Forced Air Systems	
Geothermal	65
Oil	50
Gas	50
Electric	15
Electric Resistance	10
/Apartment Block (24 units): calculated @ 2.5% of capital and installation costs	
Baseboard convection systems	
Geothermal	820
Gas	1,277
Electric Resistance @ $10/unit	240

With the exception of electric resistance heating, all the heating systems considered in this evaluation use energy for dual purposes. The primary form of consumption is for the production of heat; a smaller amount, usually electricity, is used for what can be termed as process drive--the operation of pumps, fans, controls, and other mechanical equipment.

Over the long run, the price of most conventional energy forms is expected to escalate both in relative and absolute terms. The price of these fuels, when used directly for the production of heat, will determine the type of heating systems consumers will choose to install.

The rate at which conventional fuel costs escalate is critical when considering the feasibility of the geothermal alternative. In the short term, the high capital costs which characterize geothermal energy reduce its appeal to the consumer. Over the long run, however, geothermal heating systems are relatively immune to increases in the price of energy. Once the geothermal field is developed, annual costs are restricted largely to maintenance and debt servicing. In those cases where some form of conventional energy is used to upgrade the heat content of the thermal fluid, the impact of increased fuel price is greatly diminished. In the following section, a forecast of conventional energy prices is developed.

6.4.4. Energy Price Forecast*

A twenty-year forecast of the price of the major space heating energy sources is presented in Table 6-8. The forecast was developed

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Table 6-8 follows

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as part of provincial and national scale energy demand studies recently completed by Canadian Resourcecon Ltd, and is used in Section 5.0 of this report in the analysis of diesel-electric costs.

The forecast prices of light fuel oil and natural gas are based on the Toronto city gate price of crude oil. The price of crude in real (1980$) terms is assumed to rise to 75 percent of the estimated world price by 1985 and 90 percent by 1990, the level at which it will remain through the end of the forecast period. For every $1/GJ increase in the cost of crude oil, the residential price of

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*The draft of this section was prepared in mid-1980.

TABLE 6-8. Energy Price Forecast ($/GJ)

	Crude Oil	Light Fuel Oil	Electricity	Natural Gas	
				Wholesale	Retail
1980 April	2.75	4.15	8.34	1.11	2.07
1981	3.37	4.84	8.34	1.36	2.32
1982	3.79	5.30	8.34	1.62	2.58
1983	4.18	5.75	8.34	1.88	2.84
1984	4.49	6.09	8.34	2.13	3.09
1985	4.77	6.38	8.34	2.39	3.35
1986	5.16	6.78	8.34	2.66	3.62
1987	5.50	7.18	8.34	2.94	3.90
1988	5.84	7.52	8.34	3.22	4.18
1989	6.08	7.80	8.34	3.50	4.46
1990	6.28	8.03	8.34	3.77	4.73
1991	6.47	8.23	8.34	3.87	4.83
1992	6.66	8.44	8.34	3.97	4.93
1993	6.84	8.63	8.34	4.07	5.03
1994	7.03	8.82	8.34	4.16	5.12
1995	7.22	9.02	8.34	4.27	5.23
1996	7.37	9.18	8.34	4.36	5.32
1997	7.50	9.33	8.34	4.45	5.41
1998	7.65	9.48	8.34	4.55	5.51
1999	7.78	9.62	8.34	4.65	5.61
2000	7.92	9.77	8.34	4.75	5.71

light fuel oil is forecast to increase by approximately $1.09/GJ. On an energy equivalent basis, the wholesale price of natural gas is assumed to increase from 40 percent of the price of crude in 1980 to 50 percent in 1985 and 60 percent in 1990. After 1990 the wholesale price relationship between natural gas and crude oil is assumed to remain constant. The difference between the wholesale and retail price of natural gas consists of a service component which is assumed to remain unchanged over the forecast period.

In discussions concerning the future residential price of electricity, B.C. Hydro suggested that prices would remain essentially unchanged over the forecast period.

Given the variation in the thermal efficiencies of the heating plants using these energy forms, it is somewhat misleading to compare prices only on an energy-equivalent basis. Table 6-9 presents a price forecast adjusted to reflect the difference in operating efficiencies.

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Table 6-9 follows

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TABLE 6-9. Residential Energy Price Forecast: Thermal Efficiency Adjusted ($/GJ)

	Light Fuel Oil 65% efficiency	Electricity 100% efficiency	Natural Gas 70% efficiency (retail price)
1980 April	6.38	8.34	2.96
1981	7.44	8.34	3.32
1982	8.15	8.34	3.69
1983	8.84	8.34	4.06
1984	9.37	8.34	4.42
1985	9.81	8.34	4.79
1986	10.43	8.34	5.17
1987	11.04	8.34	5.57
1988	11.57	8.34	5.97
1989	12.00	8.34	6.37
1990	12.35	8.34	6.76
1991	12.66	8.34	6.90
1992	12.98	8.34	7.04
1993	13.27	8.34	7.19
1994	13.57	8.34	7.32
1995	13.87	8.34	7.47
1996	14.12	8.34	7.60
1997	14.35	8.34	7.73
1998	14.58	8.34	7.87
1999	14.80	8.34	8.02
2000	15.03	8.34	8.16

6.5. Heating System Energy Requirements

To compare geothermal and conventional heating system capital and operating costs, it is necessary to establish the energy requirements of all systems. The amount of input energy required to produce a constant unit of space heat varies, due to differences in the mechanical design and operating efficiency of heating plants. This point is clearly illustrated by comparing the energy input requirements of forced air oil and electric resistance heating systems (Table 6-10).

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Table 6-10 follows

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Table 6-10 summarizes the annual energy requirements per account, of selected space heating systems. All figures relating to the consumption of conventional energy forms are adjusted to reflect varying equipment efficiencies. Note that the operating energy requirements pertaining to the geothermal supply and distribution network (pumps and booster boiler) are adjusted to apply only to the residential share (55 percent) of community heat load. Costs pertaining to the commercial share are not directly calculated. Table 6-11 summarizes

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Table 6-11 follows

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TABLE 6-10. Annual Energy Required by Selected Space Heating Systems (concluded)

Geothermal Heating

			100% Geothermal	70% Geothermal
Water temperature	(°C)		75	87.0
Temperature drop	(°C)		16.8	28.8
Flow rate	(l/s)	single residences	.189	n.a.
		apartment baseboards	1.827	n.a.

	Energy Requirements/Account/Annum		
	Heating (GJ)	Operating[(b)] (kWh)	(GJ) (Natural Gas)
Single Detached Residences			
100% Geothermal	121	1646	N.A.
70% Goethermal	121	1220	?
Apartments (requirements/suite)			
100% Geothermal	29	332	N.A.
70% Geothermal	29	232	?

(a) Annual pump energy requirements are estimated as (for 100% Geothermal):
Pump H.P. x 365 x 24 x Load Factor x .7457 where 1 kWh = .7457 HP hour;
1050 x 365 x 24 x .29 x .7457 = 1,989,095 kWh.

(b) Operating requirements calculated as: account's share of system pumping requirement (as determined by share of heat load) + furnace fan requirements + (if applicable) account's share of booster boiler fuel requirements. For example, the electricity requirements of a single detached 100% geothermal account are estimated at (.5 x 1,989,095 ÷ 700) + 225 = 1646 kWh.

TABLE 6-10. Annual Energy Required by Selected Space Heating Systems (continued)

Annual Heat Load Per Account (GJ/annum)		Total Annual Heat Load (GJ/annum)		% of Total
Single detached residences :	121.3	$700 \times 121.3 \times 10^3$	$= 84.9 \times 10^3$	50
Apartments :	29.1	$300 \times 29.1 \times 10^3$	$= 8.7 \times 10^3$	5
Commercial sector :	N.A.		74.9×10^3	45
		Total	$= 168.5 \times 10^3$	100

Operating (process drive) Energy -

Electricity

Forced air furnace fan - 225 kWh/single detached residence/annum

Apartment boiler circulation pump - 80 kWh/suite; 1920 kWh/block/annum

Geothermal fluid pumps - 100% Geothermal -[(a)] 1989095 kWh
70% Geothermal - .7 x 1989095 = 1392367 kWh

Natural Gas

Geothermal booster boiler - ? MJ/annum

Conventional Heating Systems		Thermal Efficiency	Energy Requirements/Account/Annum	
		%	Heating (GJ)	Operating (kWh)
Single Detached Residences:				
Energy source :	Natural gas	70	173	225
	Fuel oil	65	186	225
	Electricity (forced air)	95	127	225
	Electricity (resistance)	100	121	N.A.
Apartments (requirements/suite) :				
Energy source :	natural gas	75	39	80
	electricity (resistance)	100	29	N .A.

TABLE 6-11. Residential Sector Annual Space Heating Energy Requirements (GJ)

	Heating Systems					
	Geothermal		Natural Gas	Light Fuel Oil	Forced Air Electric	Resistance Electric
	100%	70%				
Single Detached Residences:						
Heating (GJ)	84,700	84,700	121,100	130,200	88,900	84,700
Operating ('000 kWh)	1152.2	854.0	157.5	157.5	157.5	N.A.
(GJ)[a]	N.A.	?	N.A.	N.A.	N.A.	N.A.
Apartments:						
Heating (GJ)	8,700	8,700	11,700	N.A.	N.A.	8,700
Operating ('000 kWh)	99.6	69.6	24.0	N.A.	N.A.	N.A.
(GJ)[a]	N.A.	?	N.A.	N.A.	N.A.	N.A.

(a) Geothermal booster boiler fuel consumption. Although energy requirement estimates have not been prepared, they are expected to be very small.

annual energy requirements by the residential sector.

6.6. Financial Analysis

The annual cost of operating a heating system consists of two components--a fixed cost, primarily the initial capital cost which is amortized over the operating life of the system, and a variable component, the size of which is determined primarily by the year-to-year price of fuel. The analysis converts capital cost estimates for all parts of the heating systems to annualized (1980$) costs using capital recovery factors. The mechanical life of different types of heating equipment varies widely. The use of the capital recovery factor over amortization periods reflecting actual life expectancies provides a common basis for comparison. For capital intensive projects the discount rate can be the critical estimator. In this evaluation discount rates of 6 and 12 percent are assumed.

Table 6-12 presents service life estimates and

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Table 6-12 follows

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resultant annualized capital costs of heating system components. The capital costs are summaries of the detailed cost estimates developed in Tables 6-4 and 6-6. Service lives derive from from the 1980 Systems Handbook, an

TABLE 6-12. Annualized Capital and Installation Costs

Heating System Component	Component Life	Capital Cost	Annualized Costs Discount Rate 6%	Annualized Costs Discount Rate 12%
Geothermal Wells				
100% Geothermal system	20	1,920,000	167,424	257,008
70% Geothermal system	20	1,280,000	111,616	171,392
Transmission and Distribution System				
100% Geothermal system:				
Pipelines and service connections	40	4,240,370	291,984	514,357
Pumps	20	60,200	5,249	8,061
70% Geothermal system:				
Pipelines and service connections	40	3,879,805	258,007	470,620
Pumps	20	43,000	3,749	5,758
Booster boiler	40	120,000	7,980	14,556
Home Heating Plants				
/Single Family Residence:				
Forced Air Furnaces and Controls				
Geothermal	20	1,075	94	144
Oil	20	2,070	181	277
Gas	20	1,050	92	141
Electric	35	690	48	84
Ductwork - all forced air systems	35	2,500	173	306
Electric Resistance	35	1,700	117	208
/Apartment Block (24 units):				
Baseboard Convection Systems				
Geothermal	40	32,800	2,181	3,979
Natural gas				
convectors and piping, etc.	40	32,800	2,181	3,979
boiler, controls, circulation pump	25	18,270	1,429	2,329
Electric Resistance	35	20,160	1,391	2,466
Geothermal Retrofitting				
Single Family Residence (forced air)	20	700	61	94
Apartment Block @ $500/unit (baseboard convection)	40	12,000	798	1,456

engineering costing manual. Salvage value of the fully-timed equipment is assumed to be negligible.

Heating equipment maintenance costs (Table 6-7) are assumed constant in real terms over the life of the equipment. Adding these costs to the annualized capital costs developed in Table 6-12 compares heating systems based on annualized fixed costs. Tables 6-13 and 6-14 summarize annualized costs at discount rates of 12 percent and 6 percent, respectively.

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Tables 6-13 and 6-14 follow

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Only 55 percent of the cost of the geothermal supply and distribution system--the share proportional to the residential heating load--is assigned to the annualized residential heating costs.

A conclusion from Tables 6-13 and 6-14 is that geothermal heating systems are at a capital cost disadvantage compared to conventional systems; the disadvantage is greater at the 12 percent discount rate than at 6 percent.

6.6.1. Operating Costs for Space Heating

Total annual owning and operating costs are the sum of annualized capital and maintenance costs and the cost of input energy requirements. Expenditures on energy are important in the

TABLE 6-13. Annualized Capital, Installation and Maintenance Costs, Discounted at 12 Percent (concluded)

FOOTNOTES

(a) Based on residential share of total annual system heat load (55%).

(b) Product of annualized costs/unit (Table 6-12) and number of single family residences (700).

(c) Product of annualized costs/apartment block (Table 6-12) and number of blocks (12.5).

(d) Product of geothermal production, transmission and distribution system maintenance costs (Table 6-7) and residential (single and apartment) share of energy requirements (55%).

(e) Product of costs per apartment block (Table 6-6) and number of blocks (12.5) and costs per single family dwelling (Table 6-5) and number of dwellings (700) respectively.

(6) Sum of items 6 through 13.

(g) Applies to single detached dwellings.

TABLE 6-13. Annualized Capital, Installation and Maintenance Costs, Discounted at 12 Percent (continued)

Component	Geothermal		Forced Air Systems			Electric Resistance Syste
	100%	70%	Natural Gas	Electric	Oil	
			N.A.	N.A.	N.A.	N.A.
1. Wells	257,008	171,392	N.A.	N.A.	N.A.	N.A.
2. Pipelines and service connections	514,357	470,620	N.A.	N.A.	N.A.	N.A.
3. Pumps	8,061	5,758	N.A.	N.A.	N.A.	N.A.
4. Booster boiler	-----	14,556	N.A.	N.A.	N.A.	N.A.
5. Sub-total	779,426	662,326	N.A.	N.A.	N.A.	N.A.
Residential share of geothermal production system, etc. costs (above)(a)						
6.	428,684	364,279	N.A.	N.A.	N.A.	N.A.
Heating Plants Single Dwellings(b)						
7. Furnaces & controls	100,800	100,800	98,700	58,800	193,900	145,600
8. Ducts	214,200	214,200	214,200	214,200	214,200	N.A.
Apartments(c)						
9. Convectors, etc.	49,738	49,738	49,738	N.A.	N.A.	30,825
10. Boilers & controls	N.A.	N.A.	29,113	N.A.	N.A.	N.A.
Maintenance						
11. Geothermal production + distribution system(d)	59,133	55,589	N.A.	N.A.	N.A.	N.A.
12. Heating plants:(e) Apartments	10,250	10,250	15,963	N.A.	N.A.	3,000
13. Singles	45,500	45,500	35,000	10,500	35,000	7,000
Total costs to residential sector	908,305	840,356	442,714	283,500(g)	443,100(g)	186,425

TABLE 6-14. Annualized Capital, Installation and Maintenance Costs, Discounted at 6 Percent (continued)

		Geothermal		Forced Air Systems			Electric Resistance System
				Natural Gas	Electric	Oil	
Component		100%	70%	N.A.	N.A.	N.A.	N.A.
1.	Wells	167,424	111,616	N.A.	N.A.	N.A.	N.A.
2.	Pipelines and service connections	291,984	258,007	N.A.	N.A.	N.A.	N.A.
3.	Pumps	5,249	3,749	N.A.	N.A.	N.A.	N.A.
4.	Booster boiler	—	7,980	N.A.	N.A.	N.A.	N.A.
5.	Sub-total	464,657	381,352	N.A.	N.A.	N.A.	N.A.
Residential share of geothermal production system, etc. costs (above)(a)							
6.		255,561	209,744	N.A.	N.A.	N.A.	N.A.
Heating Plants Single Dwellings(b)							
7.	Furnaces & controls	65,800	65,800	64,400	33,600	126,700	81,900
8.	Ducts	121,100	121,100	121,100	121,100	121,100	N.A.
Apartments(c)							
9.	Convectors, etc.	27,263	27,263	27,263	N.A.	N.A.	17,388
10.	Boilers & controls	N.A.	N.A.	17,862	N.A.	N.A.	N.A.
Maintenance							
11.	Geothermal production + distribution system(d)	59,133	55,589	N.A.	N.A.	N.A.	N.A.
12.	Heating plants:(e) Apartments	10,250	10,250	15,963	N.A.	N.A.	3,000
13.	Singles	45,500	45,500	35,000	10,500	35,000	7,000
Total costs to residential sector(f)		584,607	535,246	281,588	155,200(g)	282,800(g)	109,288

TABLE 6-14. Annualized Capital, Installation and Maintenance Costs, Discounted at 6 Percent (concluded)

FOOTNOTES

(a) Based on residential share of total annual system heat load (55%).

(b) Product of annualized costs/unit (Table 6-.12) and number of single family residences (700).

(c) Product of annualized costs/apartment block (Table 6 -12) and number of blocks (12.5).

(d) Product of geothermal production, transmission and distribution system maintenance costs (Table 6 -7) and residential (single and apartment) share of energy requirements (55%).

(e) Product of costs per apartment block (Table 6-6) and number of blocks (12.5) and costs per single family dwelling (Table 6-5) and number of dwellings (700) respectively.

(6) Sum of items 6 through 13.

(g) Applies to single detached dwellings.

operating budget of conventional heating systems; geothermal operating expenditures are limited to the electricity required for process drive and, in the 70 percent geothermal system, for the fuel required by the booster boiler. These sums are presented in Table 6-15 (at both discount rates). Electricity prices are forecast to remain uniform over the 20-year period of analysis and are included on that basis.

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Table 6-15 follows

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The costs of owning and operating the various heating systems during specified years are compared in Table 6-16. The estimates are developed by adding the fixed costs (at the left) to the estimated expenditures for energy during every fifth year of the period of analysis. Estimates of expenditures on energy are a product of the annual residential space heating enery requirements (Table 6-11) and the forecast price of the respective energy type (Table 6-8).

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Table 6-16 follows

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TABLE 6-15. Heating Systems: Fixed Annual Costs

	Geothermal		Natural Gas	LFO	Forced Air Electric	Resistance Electric
	100%	70%				
	Capital Costs Discounted at 6%					
Annualized Capital and Maintenance Costs:	584,607	535,246	281,588	282,800	155,200	109,288
Energy Costs:						
Operating Electricity	37,554	27,708	5,445	4,725	4,725	N.A.
Total Costs	622,161	562,954	287,003	287,525(a)	159,925(a)	109,288
	Capital Costs at 12%					
Annualized Capital and Maintenance Costs	908,305	840,356	442,714	443,100	283,500	186,425
Energy Costs:						
Operating Electricity	37,554	27,708	5,445	4,725	4,725	N.A.
Total Costs	945,859	868,064	448,159	447,825(a)	288,225(a)	186,425

(a) Applies only to single detached dwellings.

TABLE 6-16. Comparison of System Annual Owning and Operating Costs Based on the Price of Fuel in the Year

Heating System	Capital, Maintenance & Fixed Operating Costs 6% Discount Rate	1980	1985	1990	1995	2000
100% Geothermal	622,161	622,161	622,161	622,161	622,161	622,161
70% Geothermal	562,954[a]	562,954	562,954	562,954	562,954	562,954
Natural gas	287,003	561,903	732,303	914,803	981,703	1,045,503
Resistance electric	109,288	888,188	888,188	888,188	888,188	888,188
Forced air electric[b]	159,925	901,225	901,225	901,225	901,225	901,225
Fuel oil[b]	287,525	827,925	1,118,425	1,333,325	1,462,125	1,559,425
	12% Discount Rate					
100% Geothermal	945,859	945,859	945,859	945,859	945,859	945,859
70% Geothermal	868,064	868,064	868,064	868,064	868,064	868,064
Natural gas	448,159	723,059	893,459	1,075,959	1,142,859	1,206,659
Resistance electric	186,425	965,325	965,325	965,325	965,325	965,325
Forced air electric[b]	288,825	1,029,525	1,029,525	1,029,525	1,029,525	1,029,525
Fuel oil[b]	447,825	988,225	1,278,725	1,493,625	1,622,425	1,719,725

(a) Does not include costs of booster boiler fuel.

(b) Figures apply only to single detached accounts (700).

A conclusion is that at the 6 percent discount rate geothermal space heating will be competitive with the least cost (natural gas) conventional alternative before 1985. By reducing the geothermal design capacity by 30 percent, the economics of geothermal heating are further enhanced. At the 12 percent discount rate--more realistic from the economic perspective--the high capital costs of the geothermal systems offset its lower operating cost advantage. The 100 percent capacity geothermal space heating system does not become competitive with natural gas until the late 1980's; the owning and operating costs of the 70 percent capacity system fall within the competitive range by the mid-1980's.

At the higher discount rate, it is appropriate to compare geothermal costs to those of electric resistance heating. Although the costs of electrical heating exceed those of both geothermal configurations, the margin may not be sufficient to influence individual consumers to choose the geothermal option. In the case of the 100 percent geothermal system, for example, its annual costs per account (given 1 000 residential accounts) are only 20 dollars below those of electrical heating. Given the attractive operating characteristics of electric resistance heating, many consumers might well be willing to pay the 20 dollar premium and install an electrical system.

6.6.2. Space and Domestic Water Heating

After being wasted from the geothermal space heating system under consideration, the heat content of the thermal fluid could meet domestic hot water requirements. Utilization of geothermal energy for this purpose would place no additional demands on the capacity of the geothermal supply and distribution system; it would, in fact, increase the system load factor and therefore reduce costs per unit of geothermal energy consumed. The capital outlays required for domestic water would be the costs of the hot water tanks. The annual costs of operating the supply and distribution system would increase somewhat, as pumps and other components of the supply and distribution system would be operated even during seasons when space heating is unnecessary.

Estimates of the capital and installation costs of a hot water tank designed to operate with geothermal fluid were not developed in this study. It is expected that these costs are similar to those of a tank using conventional energy forms. The additional costs of operating the goethermal distribution to provide for domestic water heating needs were also not calculated; such costs would likely be low.

The costs discussed above should not be dismissed as irrelevant, but a strong position favouring combined geothermal space and water heating over the conventional alternatives is developed without them. By heating water geothermally, conventional energy is saved (e.g., 34 GJ/year/single dwelling). The inferred value of these savings indicates that geothermal space and water heating, on a scale discussed in this study, could be expected to be competitive with conventional space and water heating systems before 1985. Assuming the energy prices developed in the forecast, Table 6-17 compares geothermal costs with

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Table 6-17 follows

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those of the least cost conventional alternatives.

6.6.3. Retrofitting

We have not made an economic evaluation of installing geothermal space heating on a retrofit basis. Many of the costs of a retrofit project are likely to be site specific. The variables which can have a major impact on overall retrofit costs are:

TABLE 6-17. Space and Water Heating: Annual Owning and Operating Costs Based on the Price of Fuel in the Year

Heating System	Capital, Maintenance & Fixed Operating Costs 12% Discount Rate	1980	1985	1990	1995	2000
100% Geothermal	945,859	945,859	945,859	945,859	945,859	945,859
70% Geothermal	868,064	868,064	868,064	868,064	868,064	868,064
Natural gas[(a)]	448,159	782,656	989,908	1,212,140	1,293,436	1,371,056
Resistance electric[(b)]	186,425	1,269,642	1,269,642	1,269,642	1,269,642	1,269,642

(a) Natural gas water heating energy requirements (75% efficiency) : 33.87 GJ/annum/single dwelling; 16.84 GJ/annum/apartment suite.

(b) Electric water heating energy requirements (75% efficiency): see natural gas above.

1. the number of retrofit customers
2. the density of housing in the retrofit area
3. the retrofit project heat load
4. the type and age of existing heating equipment
5. the kind of terrain through which mains must be installed
6. the level of servicing in terms of sidewalks, roads and utilities, already in place.

The last three factors are likely to be most influential. In buildings where the existing heating system does not include conduits or ducts, structural modifications would be necessary. Difficult terrain can be responsible for a marked rise in construction costs. If excavation for the installation of distribution mains required reconstruction of sidewalks, roads, sewers, and other utilities, construction costs could be prohibitive.

Retrofitting costs are estimated only as the capital expenditures necessary to re-equip the individual home. These are about $700 per single detached residence and $500 per apartment suite. If the single detached residence currently has a forced air oil furnace, the geothermal retrofit system has a payback period of approximately 1 year; if it has a natural gas system, the payback period is roughly 2 years. The payback period for retrofitting an apartment suite to geothermal heating is approximately 6 years at present natural gas prices.

6.7. Conclusions

The model and variants described indicate that geothermal space heating is economically competitive with, or superior to, heating with conventional energy sources, subject to many conditions. Some of these conditions were covered as favourable assumptions in the construction of the model; others resulted from the calculations performed. A summary of the conditions follows:

1. Exploration for the resource must be successful, and the cost charged to the project must be within economic limits;
2. Development cost must be acceptable; and the properties of the developed geothermal fluid must be suitable;
3. Location is important: the community must be in or be built in a geothermal area; Table 6-18

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Table 6-18 follows

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lists some existing communities in British Columbia

TABLE 6-18. Communities Near Prospective Geothermal Resources

1. Lower Mainland

   Pemberton, Bralorne, Gold Bridge, Squamish, Brackendale, Mt. Currie, Agassiz, Harrison Mills, Chilliwack

2. Vancouver Island

   Tofino, Ucluelet, Port McNeill, Port Alice, Port Hardy

3. Coast and Queen Charlottes

   Bella Coola, Bella Bella, Terrace, Kitimat, Prince Rupert, New Aiyansh; Tasu

4. Northwest

   Atlin, Telegraph Creek, Tahltan, Iskut, Dease Lake

5. Okanagan and Interior

   Vernon, Kelowna, Peachland, Summerland, Oliver, Osoyoos, Horsefly, Likely; Takla Landing

6. Southern Rockies

   Trail, Castlegar, Nelson, Nakusp, Kaslo, Kimberley, Cranbrook, Fernie, Sparwood

7. Central and Northern Rockies

   Valemount, McLeon Lake, Toad Lake, Muncho Lake, Liard Crossing

8. Northeast Basins

   Fort St. John, Dawson Creek, Fort Nelson which are in or near geothermal areas (derived from Section 3.0 of this report);

4. Specific location is also important: pipeline length cannot exceed whatever capital cost limits are appropriate, nor can pipelines be so long that the geothermal fluid loses too much heat in transit;

5. The probabilities of ever providing geothermal space heating for a community of 3 000, as used in the model, are not known; certain assumptions as to design, building mix and heating load were made, and these would vary from place to place;

6. Smaller markets, for example, should not be overlooked;

7. Peaking capacity needs in a more temperate zone (than the Terrace area, which was used in the model) would be lower, and any economic edge for geothermal heating would be enhanced; or diminished in a colder zone;

8. A new community or an expanded subdivision of an existing community would be generally more appropriate for geothermal heating than retrofitting an existing community;

9. Where natural gas or system electric service is not available, the economic advantage of geothermal

is enhanced; and in particular, where electrical energy is diesel generated, and geothermal heating could be a downstream by-product of geothermal electric power (see Section 5.0 for the economics, and Appendices D-F for physical factors), the economic advantage is outstanding;

10. Where the community is a remote, one-purpose, logging or mining community, and geothermal energy could be used for industrial purposes, the shared cost elements and economies of scale would enhance economic attractiveness of residential heating.

What was not covered in the discussion of the economic model is the identity and nature of the explorer-developer whether this entity is a municipal district, a provincial government group, a utility company, an individual entrepreneur, or a resource company. The initial question, of course, regards who will be interested in taking the exploration and development risk. The elements of this are discussed in Appendices E (Exploration and Drilling Costs), G (Direct-Use Parameters) and I (Legal Considerations), and Section 7.0 (Rate of Penetration).

7.0 PARAMETERS FOR PENETRATION OF GEOTHERMAL ENERGY AS A SIGNIFICANT SOURCE

7.0. PARAMETERS FOR PENETRATION OF GEOTHERMAL ENERGY AS A SIGNIFICANT SOURCE

7.1. Introduction

To put the various electric and direct-use energy models into perspective, they are arranged in Drawing 7-1 in terms of useful capacity. The items are:

1. 50-400 MW system electric plant from Section 4.0
2. 1 500 kW local electric plant from Section 5.0
3. 3 000-population space heating system from Section 6.0
4. fish farm from Appendix H
5. wasted hot spring heat from Section 3.0, Table 3-2.

There are different temperature requirements and different floors on the amount of energy extracted by each system, and there are different proportions of wasted energy in each. Therefore this is not a measure of the strength of the required geothermal systems. Drawing 7-2 integrates base and peak loads and develops the same information on an annual basis.

Different time spans are used in the economic analysis of the different models. Economic analysis was performed on the system electric plant for the period 1991 through 2015, allowing ten years for exploration and development during the period 1981 through 1990. For

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Drawings 7-1 and 7-2 follow

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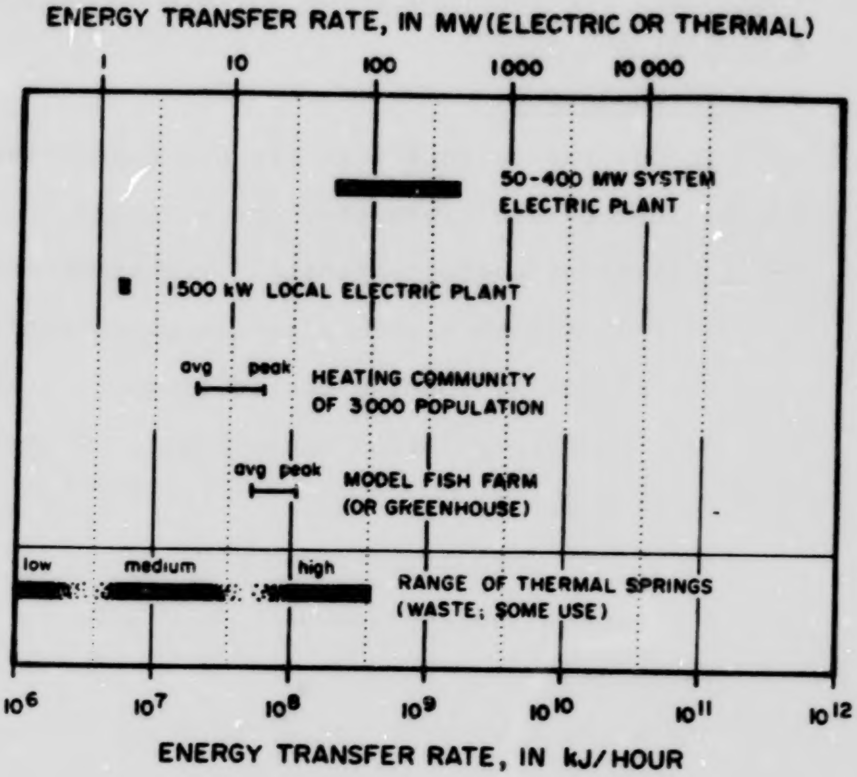
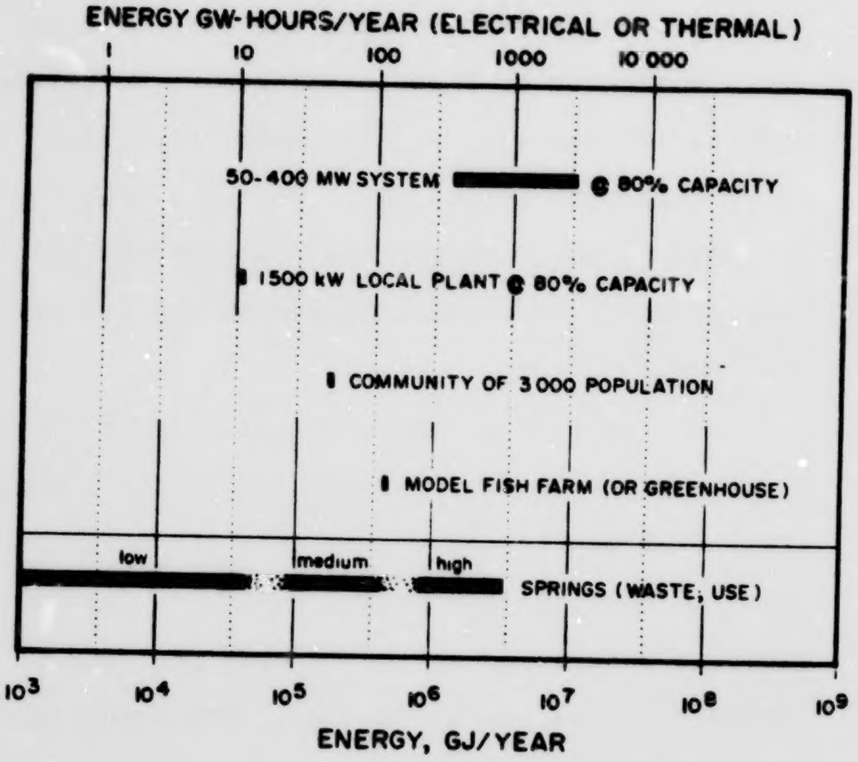


DRAWING 7-1

COMPARISON OF ENERGY CAPACITY OF ECONOMIC MODELS (Sections 4.0 - 6.0, & Appendix H) AND REFERENCE THERMAL SPRINGS (Table 3-2)



DRAWING 7-2

ANNUAL ENERGY TRANSFER OF MODEL SYSTEMS, AND THERMAL SPRINGS purposes of economic modelling, local electric generation was compared with diesel generation during the period 1981 through 2000. The same fuel cost model and time period was used for the analysis of space heating for a community of 3 000 population. No particular time period was used for the model fish farm, although an amortization period of 15 years was suggested.

All of the time periods are flexible and the economic models can be shifted, provided shifts account for changed conditions.

This section is the most speculative in the report. We attempt to develop various models for the rate of penetration of geothermal energy into the power source sector over the next 35-year period ending in year 2015. System electric generating is the largest use, and is the most valuable in the energy economy. The emphasis, therefore, is placed on system-electric.

Initially, we assume that work will continue for the next 35 years under existing legislation and procedures; in particular,that B.C. Hydro and Power Authority is the only entity having an interest in developing geothermal power. Subsequently (in Sections 7.5 to 7-7) we consider the rate of penetration if the milieu which constitutes the private sector participates in exploration and development of geothermal resources.

No other geothermal exploration is underway at the present time in British Columbia, although from time to time owners and users of hot springs undertake improvements. The title to the use of hot spring resources has been obtained under other statutes.

7.3. System Considerations in British Columbia

At present, and for the foreseeable future, new generating plants are required to meet the energy (or base load) demands of the system, rather than peak demands. This is normal for systems dominated by hydroelectric developments, where it is usually economical to install excess incremental capacity to capture more of the available energy. This raises two general comments on the possible role of geothermal energy in future system requirements:

1. When examining future system requirements, growth in energy demands might be the controlling factor on new plant additions;
2. It is reasonable to assume that geothermal plants will operate at a high capacity factor, governed by field and plant limitations rather than system limitations. As a result, geothermal

energy would generally fit in well with system development.

The period 1988-93 has been selected to examine growth in system requirements. This corresponds to the earliest period in which geothermal plants could be commissioned. There is a large difference between various forecasts for this period. For example, contemporary forecasts (September 1978) showed the following differences in the rate of energy demand growth:*

1. B.C. Energy Commission: 1 300 GWh/yr annual growth
2. B.C. Hydro: 3 300 GWh/yr annual growth.

Over a five-year period, a large geothermal field might be developed to about 400 MW: 50 MW units in years 1 and 2 and 100 MW units in years 3 to 5. A 400 MW plant would supply 2 800 GWh/yr, compared with forecasts of system demand growth over the five-year development period ranging from 6 500 GWh/yr to 16 500 GWh/yr. Thus, even with the lower forecast, geothermal development would not meet total system growth. It must be considered in conjunction with other alternative power sources.

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*Total B.C. Hydro system including transmission and distribution losses, for the period April 1988 to March 1993, inclusive.

Public information (B.C. Hydro, 1979, 1980b, 1980c, and various public hearings) suggests that the following projects have been or are currently being considered by B.C. Hydro. The year stated represents Hydro's estimate of the earliest feasible in-service date, as of October 1979:

1. Hydro, developed rivers:
    - a. Peace River, Site C (1987): 975 MW; 4 290 GWh/yr.
    - b. Columbia River, Murphy Creek (1988): 400 MW; 2 100 GWh/yr.
    - c. Kootenay Diversion: 800 GWh/yr net.
2. Thermal:
    - a. Hat Creek (1987): 2 000 MW; 11 400 GWh/yr average (500 MW units).
    - b. East Kootenay, waste coal (1989): 600 MW; 3 680 GWh/yr.
    - c. Nuclear (1994): 1 200 MW+; 8 500 GWh/yr.
3. Hydro, undeveloped northern rivers:
    - a. Stikine-Iskut (1991): 2 670 MW; 14 090 GWh/yr (first project 1 005 MW & 5 240 GWh/yr).
    - b. Liard River (1993): 4 650 MW; 24 400 GWh/yr (first project 2 640 MW & 13 900 GWh/yr).

Site C is being proposed by B.C. Hydro as the next project for development, with a possible commissioning date around 1987. No firm plans have been announced for a project to follow Site C. The timing of the next project is also indefinite, because of uncertainties in load growth. Considering the uncertainties in medium and long term system planning, we can foresee two potential roles for geothermal energy. They are:

1. In conjunction with other developments, such as Murphy Creek or East Kootenay coal, to serve as a bridge between Site C and development of one of the northern rivers;
2. In conjunction with other developments, such as Murphy Creek, East Kootenay coal and Hat Creek, to serve as an alternative to northern river development in the early 1990s.

Clearly, decisions on northern rivers will have an important bearing on the eventual usefulness of geothermal energy in meeting system requirements. Either one of the northern hydro options could supply 5 to 10 years growth in system demands, but the timing and outcome of the key decisions on these projects cannot be predicted at the present time.

It is reasonable to assume that the utility is interested in continued geothermal exploration for those reasons. A proven reserve would provide an option for the late 1980s or early 1990s. If the exploration is successful, the cost of geothermal development would be reasonably competitive with alternative projects; and the resource could be developed in conjunction with other "southern" power sources, either as a bridge preceding northern hydro developments, or as a longer term alternative to these developments.

7.4. Rate of Penetration

7.4.1. System Electric

The rate of penetration of geothermal energy into the system electric market is difficult to project at the present time, because it depends more on future events than on past events or known data. The most notable future event is the outcome of current exploration.

We submit four speculative models for future system electric development. The "low" rate of penetration is zero and presumes that geothermal energy will not be developed for system electric use in the period ending year 2015. The remaining three models are given in Drawing 7-3.

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Drawing 7-3 follows

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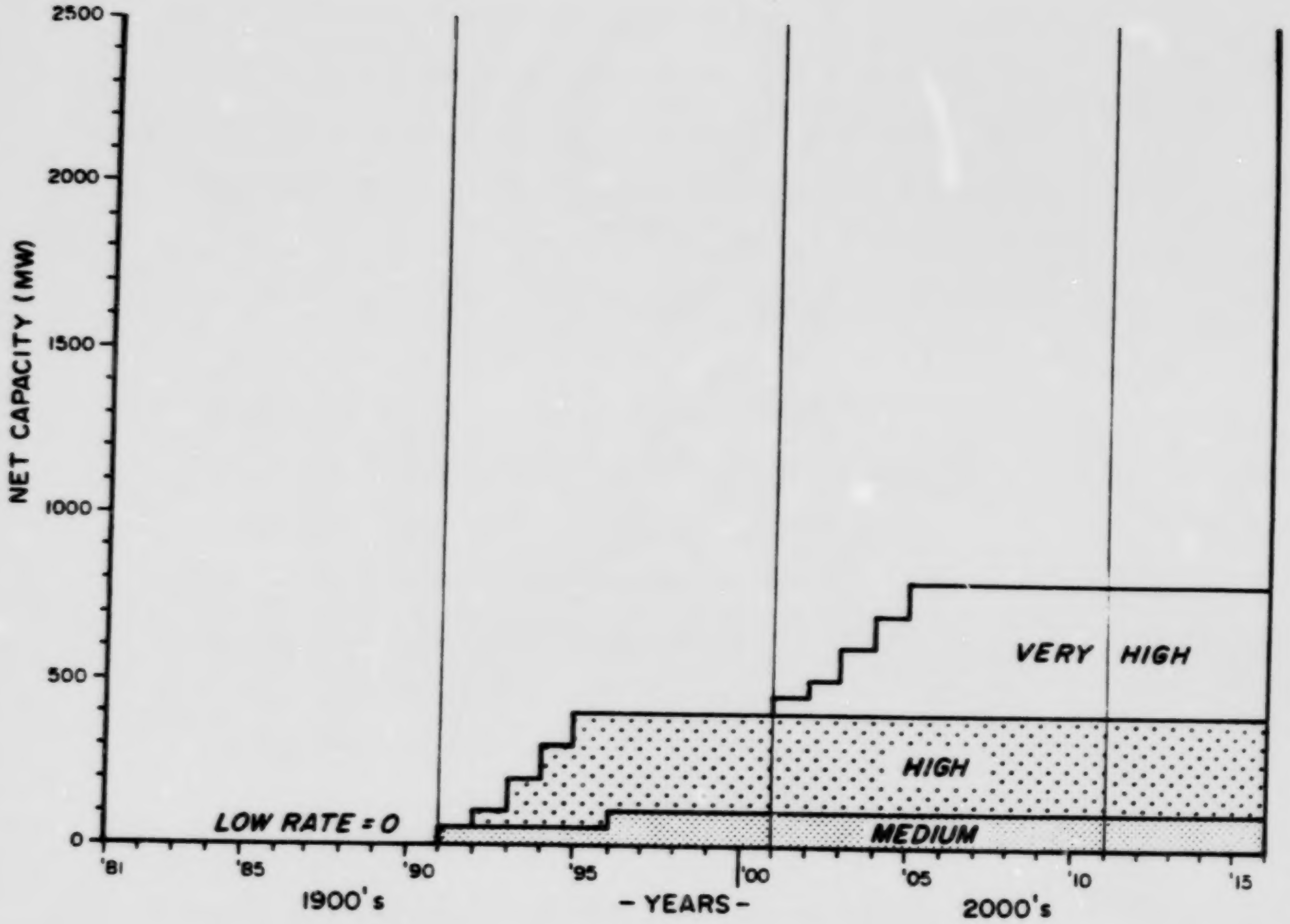
The "medium" case presumes that exploration on the lower mainland will be a qualified success. Development will proceed and two 50 megawatt plants will be commissioned, one in 1991 and one in 1996.



DRAWING 7-3

FOUR SPECULATIONS ON RATE OF PENETRATION OF GEOTHERMAL ENERGY FOR SYSTEM ELECTRIC POWER, 1981-2015, B.C. GEOTHERMAL RESOURCES ACT (1973)

The small plants would be installed, not so much to make a contribution to the system, as to learn to handle geothermal fluids and generating facilities, with the intent of future use of these engineering skills.

The "high" rate of penetration assumes that a discovery would be incremented to 400 MW capacity by 1995. The "very high" rate of penetration assumes a repeated discovery and development of the same character following ten years of additional effort.

7.4.2. Other Uses

The other geothermal utilization models described--local-electric and direct use--are not shown in Drawing 7-3. The scale of the drawing is too large for the quantities of energy transferred in such systems. It might be assumed that two or three local electric plants might be developed in the 35-year period. However, it is difficult to imagine who such a developer might be as long as the Crown holds geothermal rights according to the Geothermal Resources Act.

Direct utilization is another matter. Rising costs of fossil fuels will prompt entrepreneurs to conduct small scale exploration and development projects on existing and known thermal springs, gradually expanding the scope of development, if successful. We speculate that two to five projects may evolve and grow during the next three and one-half decades. Resources under 121°C are not reserved by the Crown under the Geothermal Resources Act, and the energy transferred in the two direct use models given is less than the energy wasted by some of the more powerful hot springs in the province.

7.5. Exploration and Development by the Private Sector

7.5.1. Introduction

The private sector in the geothermal industry elsewhere is generally made up of oil companies, mining companies, publicly traded exploration companies and other groups. In assets and stature, these entities range from individuals to multinational companies. In outlook, most have experience in other mineral or energy resources, or in other high-risk ventures. The goals of entities in the private sector are generally a given rate of return on invested capital, in the short- or long-term.

The private sector has not undertaken geothermal exploration in B.C., notwithstanding the existence of an exploration-oriented infrastructure, for several reasons:

1. absence of leasing and licensing provisions
2. no guarantee of marketability of energy
3. nonexistence of tax structure, expensible costs, tax credits
4. no other incentives.

The private sector of the Canadian economy has been active in geothermal exploration and development in the U.S., where the above-listed factors have been resolved in the last decade.

If the government of British Columbia considers it desirable to allow private-sector development of geothermal resources, the broad objectives might be stated as:

1. To develop geothermal resources
2. To facilitate the inventory of the geothermal resource base, including deposits which are potentially valuable and are subcommercial at the present time
3. To maximize the net benefits to the provincial Crown
4. To provide for a regulatory administrative framework for exploration, development and utilization.

In addition to ongoing administration of geothermal exploration and development, the government would have to consider two initial factors:

1. The present pent-up exploration desire of the private sector, and
2. "Grandfather rights" of B.C. Hydro

The Geothermal Resources Act, only recently permits the development of the resource by the private sector. Even so, in the last ten years geologic knowledge has advanced to such a point that specialists in the field would know several attractive locations in which to commence exploration. The caretaker provisions of the Act have resulted in pent-up exploration energy.

It is assumed that, if the private sector is permitted to participate in the utilization of geothermal resources, then special consideration must be given to the British Columbia Hydro and Power Authority, which has been exploring for geothermal resources at Meager Creek since 1973.

There is considerable precedent deriving from English (and German) common law in allowing the private sector to explore and develop mineral deposits of all types.

The private sector has played an important role in the development of geothermal resources in other jurisdictions. Even in New Zealand, where geothermal energy is vested in the Crown in conclusive fashion, and the Ministry of Works and Development is active in the field, licencing of the resource is common and private industry has been successful in exploiting geothermal energy (Dench, 1967).

Aside from possible idealogical preferences, there are no apparent advantages to be gained by departure from the present system of resource development in Canada, in which federal and provincial governments provide an institutional and a legal infrastructure under which the private sector can operate. Just as the oil and gas and the mining industries provide opportunities for the junior, medium-sized and major participants, the legislative framework for geothermal development in British Columbia should consider the involvement of a similarly diverse range of players.

7.5.2. Sensitivity of Exploration to Institutional Factors

Consider exploration to the point of discovery. Exploration goals may differ: A utility may wish ultimately to produce power at the lowest cost; a private-sector company may wish ultimately to obtain a given rate of return on an investment, or to "discover" an asset which will double or triple the company's share price. From the province-wide standpoint, the goals of different groups affect the completeness of exploration (inventorying of geothermal resources and reserves) and the efficiency (reserves discovered and proven per dollar spent).

It is relatively rare for electric utility companies to initiate and stand the full cost of exploration in instances where geothermal fields are obscure and not obvious. Those electrical utilities which have developed geothermal power at their own initiative--in Italy, New Zealand, Mexico, etc.--have done so on obvious, large, boiling target areas. In the United States most exploration is initiated and managed by mineral resource companies. Utilities may join with the resource companies at some stage, but it is generally not until after the explorers have culled through several prospective targets and there is reason to believe that a useful geothermal resource is present.

A utility may not have the risk capital and the staying power to make a geothermal discovery and to extend the discovery into a measurable field. A disincentive for drilling exploratory wells is that each dollar costs a dollar. Resource companies write off drilling costs against other income and exploration dollars cost substantially less.

It would be logical to expect a utility to undertake geothermal exploration as geothermal power development is perceived to fit the system. In particular a utility might be concerned with growth of base load. A utility could not be expected to have any incentive to inventory the geothermal resources throughout the province by systematic exploration. Nor could a utility be expected to undertake several geothermal exploration projects at one time.

A utility could not be expected to invest in capacity for export markets, or to undertake high-risk geothermal exploration and development for the specific purpose of export.

The private sector, on the other hand, behaves very differently from a utility in exploration. First, the private sector is decentralized and diverse. Centralized thinking and control are not attributes which lend themselves to exploration. The diversity of thought, ambition and competition which derives from the milieu is recognized within the industry. The aggregate of small companies outperforms multinationals to the point of discovery in both metal and petroleum exploration.

Exploration success is often traced to the initiative and persistence of one or two individuals. It is often deferred by committees of administrators and engineers. A decision-maker in a resource company knows that his role is to take risks and to drill a "wildcat" well from time-to-time, based upon experience, intuition and potential reward. In general, this is not the role of a decision-maker in a utility company. The milieu of the private sector operates with different motives than a utility's rational projections. The private sector operates with a profit motive. This means an extraordinary profit, commensurate with the risk, when exploration alone is considered, e.g., risk, discovery, sell out. Private sector thoroughness in geothermal exploration could be expected to respond directly to overall energy prices, confidence in government regulation of pertinent business activities, variations in economic cycles, and competition in capital markets.

This means that if appropriate regulations and a broad energy market exist, exploration and inventory of geothermal resources in B.C. would proceed independent of any one utility's projection of load growth.

Assuming that just and equitable legislation and regulations were promulgated, which would tend to attract private-sector initiative in geothermal exploration in B.C., there are two remaining questions to be resolved:

1. tax treatment and
2. marketing of power to a system dominated by one utility.

These factors are discussed in more detail in Appendix I.

7.6. System Electric Eonomic Model

7.6.1 Review

The economic model for 50 MW system electric by a utility, analyzed in Section 4.0, is reviewed here under the assumption that the private sector would have a hand in geothermal development. Private sector involvement introduces two additional factors in the economic evaluation:

1. Revenue requirements (and hence the average cost of energy) changes because the methods of financing are different than for a utility and income is taxable;
2. Because of the risks involved, explicit consideration might be given to possible incentives for encouraging exploration and development.

This section examined energy costs from a private sector viewpoint, and indicates the impacts of plausible incentive mechanisms on these energy costs. Two general conditions are examined: first, private sector development of the geothermal field in combination with utility development of the plant and transmission facilities;* and second, private development of both the field and plant facilities.

All of the evaluations are made with reference to the hot water (Case 2) resource defined in Appendix F and Section 4.0. This type of resource appears to be reasonably cost competitive and offers reasonable prospects for discovery. The probability of discovering a dry steam resource (Case 1) is unknown at the present time, but it should be noted that the cost of developed energy would be less than the costs estimated in the following models.

7.6.2. Basis for Evaluation

Financial analyses were carried out in current dollars, to account for the effects of income tax and other overheads. However, the model used calculates a revenue that is levelized in 1980 constant dollars (i.e., a revenue that increases at the general inflation rate) to yield a specified rate of return on equity under specified financial assumptions. This levelized revenue is comparable to the levelized cost used in the economic analysis of Section 4.0.

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*This is a common practice in operating and proposed geothermal installations in the U.S. The utility buys the steam from the field operator.

For example, if a utility were to buy steam from a resource company, they would treat the revenues earned by the field operator as a cost in their evaluation. While the actual revenue pattern might be different (in particular, higher in the initial years and lower in the later years), the levelized revenue approach gives a reasonably accurate picture of the long-term economics.

Unless specified otherwise, for sensitivity analysis, the following parameters were employed in the financial analysis model (all values expressed in current dollars):

1. Percent equity on exploration investment: 100%
2. Percent equity on other investments: varied, 15 to 100%
3. Rate of return on equity, after tax: 20% (discounted cash flow basis)
4. General inflation rate: 6%
5. Interest on debt: 11%
6. Debt retirement period: 20 years
7. Federal tax rate: 36%
8. Provincial tax rate: 15%

9. 30 years' operation, with replacement of wells at an average life of 15 years

10. Exploration investments earn a tax credit in the year of expenditure

11. Well development expenditures earn an effective capital cost allowance of 30% commencing in the year of expenditure

12. Gathering system expenditures earn a capital cost allowance of 6% starting in the first year of operation

13. Notwithstanding the lease rentals and royalties described in Appendix I, those are not specifically included in this economic model.

The investment and operating costs used in the analysis are as shown for Case 2 in Tables 4-1 and 4-2. Note that the investment costs exclude interest during construction, which is handled separately in the financial analysis.

7.6.3. Private Sector Field Development

In this case, it is assumed that a resource company will develop the field and gathering system and sell steam or a mixture of hot water and steam to a utility, which in turn will own and operate the power plant and transmission facilities. For convenience revenues are calculated for the geothermal fluid in mills/kWh of generation obtained from the fluid. As a reference, the levelized costs of geothermal fluid delivered to the power plant under utility financing are estimated as shown in Table 7-1.

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Table 7-1 follows

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Table 7-2 shows the levelized costs

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Table 7-2 follows

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(revenues) of steam with private sector development under different financing conditions and tax rates. The results are discussed briefly below (the model numbers are shown in Table 7-2). The steam costs of the various models are added to generating costs of Table 7-1 to arrive at a cost to the utility.

Model 1. With 100 percent equity financing, the projected steam cost is the equivalent of 34 mills/kWh, and the total cost of electric energy to the utility would become 47 to 56 mills/kWh. This makes geothermal energy non-competitive with other sources in the utility analysis (Table 4-4).

TABLE 7-1. Levelized Costs

Geothermal Power Developed from a Hot Water Field by a Utility (Case 2 of Section 4.0 and Table 4-3) Partitioned into Estimated Components of Steam Supply and Power Production

	Mills/kWh		
Discount Rate (%)	Steam Supply	Generation & Transmission	Total
3	11.8	13.0	24.8
6	15.2	16.6	31.8
10	21.3	22.1	43.4

TABLE 7-2. Levelized Steam Costs @ 50 MW(net): Private Sector Development

Model Number	% Debt (Wells & Gathering)	Return on Equity %	Federal Tax Rate %	Provincial Tax Rate %	Capital Recovery Factor	Levelized* Steam Cost mills/kWh
Results @ 30 Years' Operation						
1	0	20	36	15	.240	34.1
2	0	17	36	15	.185	27.0
3	0	20	36	0	.215	31.0
4	0	20	0	0	.187	27.2
5	50	20	36	15	.165	24.4
6	75	20	36	15	.127	19.6
7	75	17	36	15	.106	16.9
Results @ 15 years' Operation						
1A	0	20	36	15	.266	37.5
6A	75	20	36	15	.145	21.9

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*Levelized in 1980 constant dollars, including annual capital-related charges and operation, maintenance and administration costs.

Model 2. The after-tax return on equity is lowered from 20 percent to 17 percent, which reduces the steam cost from 34 to 27 mills/kWh. This might be a realistic return for a resource company if some of the risk could be removed, for example, if an assured market were provided.

Models 3 and 4. These two cases show the effects of removal of provincial taxes and federal/provincial taxes from Model 1. With both taxes removed, the steam cost is lowered to 27 mills/kWh, but the electric energy cost would remain relatively high in the utility analysis at 40 to 49 mills/kWh.

Models 5 and 6. These two cases show the effects of 50 and 75 percent debt financing of the costs of wells and gathering system. Exploration remains 100 percent equity. The access to debt financing has a significant effect on the steam costs. At 75 percent debt financing, the steam cost is lowered to 20 mills/kWh and the total electric energy cost to 33 to 42 mills/kWh. In this range, geothermal energy is again competitive with coal-fired thermal power (with reference to Table 4-4).

Model 7. This case shows the effect of a reduced rate of return on equity, with 75 percent debt financing. With a relatively high level of debt financing, the steam costs are less sensitive to return on equity. In this case, reducing the return from 20 percent to 17 percent reduces steam costs by only 3 mills/kWh.

The foregoing provides an indication of the sensitivity of steam costs to different types of financial conditions. The results shown in Table 7-2 reflect the major variables affecting steam costs. Other variables used in the analysis are less important. For example, reducing the economic life from 30 to 15 years increases the steam costs by only 2 to 3 mills/kWh (Models 1A and 6A). Escalation rate variations can also affect the calculated steam costs by 1 to 3 mills/kWh.

An interpretation drawn from this analysis is that resource companies may not wish to explore for geothermal energy unless government makes deliberate commitments to private development. The outlook could be improved by a twofold commitment:

1. A commitment could be made by the government and the utility to support development of geothermal energy for system electricity if the delivered energy cost is competitive with the marginal costs of coal generation. This could provide

some assurance of a market if a good discovery is made.

2. Additional economic incentives would be appropriate to bring costs in line with a competitive price. Guaranteed loans on development costs would be an effective way of achieving this objective. A guaranteed loan program has been available in the U.S.,* covering up to 75 percent of geothermal development costs. Provincial and federal tax rebates would provide a similar mechanism. These economic incentives would merely serve to bring the cost structures of private and public sector development closer together. They would not represent an additional cost to the government, compared with public sector power development.

The benefits to be gained by such commitments and incentives would be improved chances of making geothermal energy a timely option: the more exploration, the better the prospects of discovery.

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*At the time of writing of the first draft, November, 1980. The program is expected to be terminated under the Reagan Administration.

7.6.4. Private Sector Development of Field and Plant

This analysis examines revenue requirements for a case with private sector development of both field and plant facilities. As in the preceding section, the costs of developing hot water (Case 2) resource are used.

Three types of markets might be open to a private developer: direct sales to an industrial plant in the vicinity of the resource; wholesaling of power to a provincial or a municipal utility; and export sales. Since the revenue requirements for any new project might exceed the average tariffs in the existing provincial system, potential industrial markets might be confined to plants that would be remote from the existing system.

For the other markets, agreements would be required with the utility, either for sale of the power or for transmission through the provincial system, subject to changes in legislation.

Revenue requirements have been calculated as if the developer would operate as a private utility. This appears to be a likely basis for negotiation of rates between the developer and buyer, regardless of how the development is regulated.

Revenue requirements have been calculated on a yearly basis using utility revenue setting principles, and the results have been levelized in 1980 dollars to provide a consistent basis for comparison with the preceding analyses. Table 7-3

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Table 7-3 follows

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shows the results of these analyses for representative cases concerning financing, tax incentives and rate of return.

The levelized revenue requirements shown in Table 7-3 compare well with the levelized costs of utility-financed energy, which was shown in Table 4-3 as 25 mills/kWh for a 3 percent discount rate, 32 mills/kWh for 6 percent, and 43 mills/kWh for 10 percent.

Interpretation of the results shown in Table 7-3 is as follows:

1. Return on equity has an important bearing on the results, as shown by the comparison of Models 8 and 9. The 17% after tax rate would be reasonable given a long-term contract on sale of energy.
2. From the provincial viewpoint, the long-term cost of energy would be 41

TABLE 7-3. Revenue Requirements with Field and Plant Development by Private Sector

Basis: 50 MW; electric energy delivered to utility's transmission system; revenues based on utility regulation principles.

Model Number	% Debt(1)	Return on Equity %	Federal Tax Rate %	Provincial Tax Rate %	First Year Operation (2)	Levelized Over 30-year Life (3)
8	75	17	36	15	68-73	44
9	75	20	36	15	76-81	51
10	75	17	36	0	63-68	41
11	75	17	0	0	56-62	38

(1) Excluding exploration, which is assumed to be financed from equity.

(2) Range shown reflects various assumptions concerning depreciation calculation.

(3) Revenues increasing at general inflation, to provide specified DCF return on equity over 30 years' operation.

mills/kWh (1980 $), as represented by Model 10, which excludes provincial taxes. With the utility development, the corresponding cost would be 25 to 43 mills/kWh depending on the discount rate employed. As long as capital is given a reasonably high opportunity value, the only difference between the private and public sector development is the federal tax component which represents about 3 mills/kWh.

3. Under utility revenue setting principles, the revenues tend to be high in the first year and then decline over time in real terms. This is seen in the comparison of figures in the last two columns.
4. The sales price would probably look reasonable in the export market, provided that the buyer had assurance of a long-term supply contract; otherwise, the high prices in the early years would make selling hard.

The above analysis again points out the need for two key incentives: reasonable assurance of a market if exploration is successful, and access to debt capital. Tax incentives would also be a stimulant for exploration--particularly on exploration costs. Consideration could also be given to making the export market more readily available if there is no local market for the power.

7.7. Rate of Penetration of Private Sector or Mixed Private-Public Development

Where the private sector is concerned, development is sensitive to rate of return and development is absolutely dependent upon the availability of discoveries. Exploration--to the point of discovery--is an activity which can assume various levels of intensity, often in volatile response to political, economic and marketing conditions. The following discussion examines exploration and development separately and together.

If disincentives are removed, and certain incentives are substituted, as described in the foregoing and in Appendix I, the private exploration community present in B.C. and in Canada will take notice of geothermal resources, and will explore to the extent commensurate with the potential economic rewards.

A significant exploration effort, put forth over a period of a decade or more by the private milieu, may be expected to discover and prove geothermal energy reserves which are (a) clearly commercial at the time of discovery, (b) sub-commercial, but perhaps useful in the future (refer again to Drawing 2-3), and (c) sub-commercial for the most valuable application--system electric--but which can be put to use for local electric or direct heating.

Exploration is generally conducted with equity capital; but, not all resource companies involved in exploration have sufficient capital for development and production. The Canadian exploration community in particular is noted for a large number of small publicly financed and publicly traded resource companies which accept high risks in the search for high-value mineral deposits of any type. Upon a discovery, small resource companies often "farm-out" or joint-venture the project with larger and better funded groups.

Our opinion--which is speculative--on the penetration of geothermal resources as a significant source of stationary energy in B.C. is based on:

1. perceptions of the geologic factors (Section 3.0) and large areas for potential resource occurrence
2. the promulgation of legislation, regulations, tax treatment and marketing support which will encourage private sector interest in exploration and development
3. an appreciation of the efficiency and expertise of Canadian private enterprise in exploration and development of mineral resources of all types

4. a developing data base in the western U.S. for accelerated geothermal exploration and development which can be extrapolated to B.C. with appropriate caution.

Drawing 7-4 is the private-sector counterpart of Drawing 7-3, for the utility alone. We speculate that the "low" rate of penetration will be greater than zero (as in the utility's case), and will reach about 600 MW by year 2011; this model starts out at the level of the utility"s "medium" rate, and adds increments to beyond the 200 MW level in the mid-1990's. The "low" model eventually, in year 2006, exceeds the "high" capacity of 400 MW in the utility's model.

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Drawing 7-4 follows

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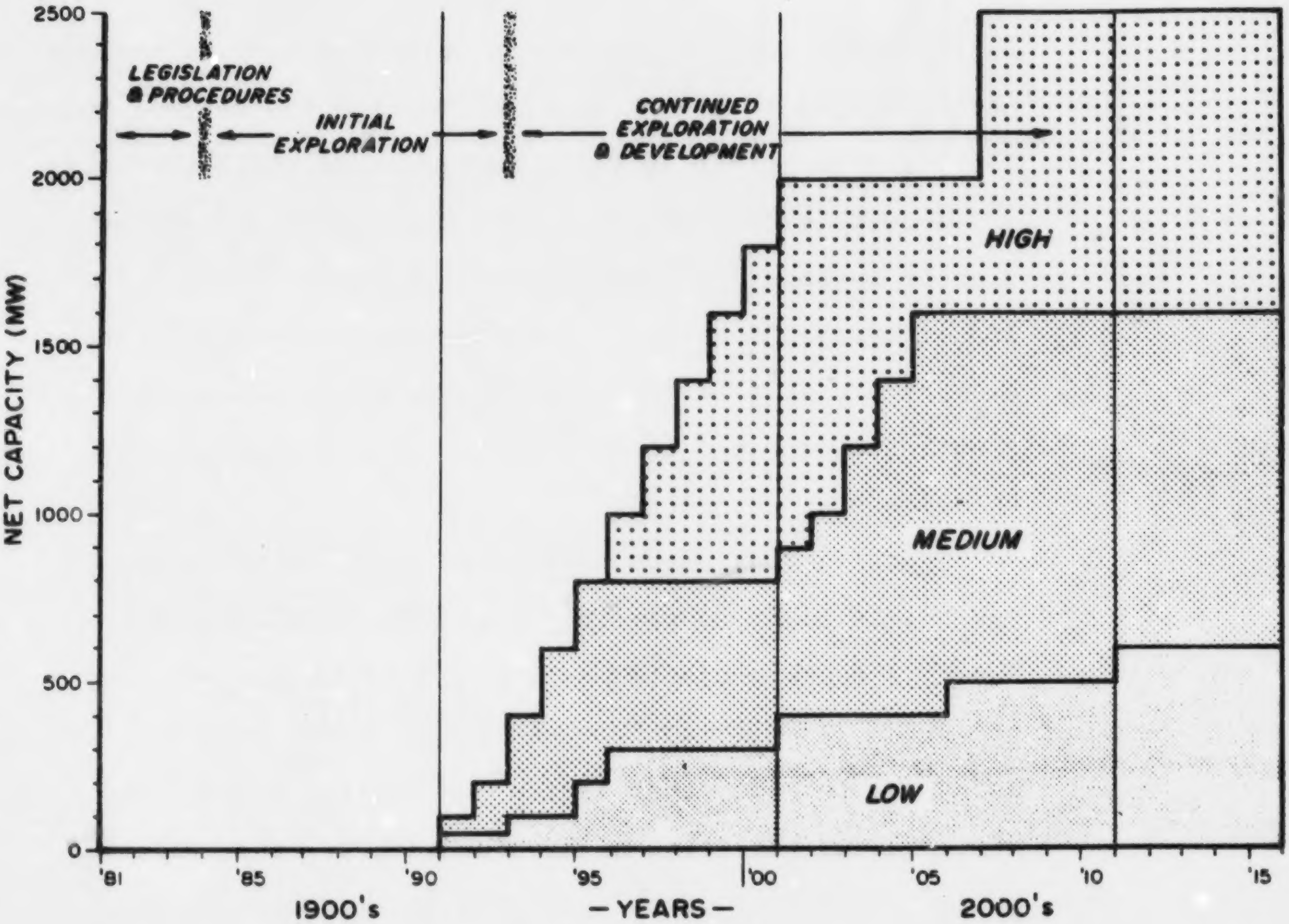
The "high" private-sector model presumes excellent marketing opportunities to utilize a correspondingly high discovery rate. Capacity grows to 2500 MW in year 2006, adding increments at a rate of 200 MW per year from 1993 to 2001, during the period of greatest growth. This rate has not been sustained by any single geothermal project in the world to date, but there is no inherent reason why such rapid development will not take place in the future, in one or more projects in a given country, state or province.



DRAWING 7-4

THREE SPECULATIONS ON RATE OF PENETRATION OF GEOTHERMAL ENERGY FOR SYSTEM ELECTRIC POWER, 1981-2015, UNDER LEGISLATION ENCOURAGING PRIVATE SECTOR

The "medium" rate of penetration assumes that two major fields (or the equivalent number of smaller fields) are developed to 800 MW each, one during the period 1991-1995, and the other 10 years later. Each of these fields would be developed to the approximate magnitude of the present Geysers (California). It is assumed that the industry-wide "learning curve" deriving from rapid expansion at the Geysers (at about 110 MW/year during the high-growth stage) would be brought to bear on more rapid developments as described.

Section 7.4. speculated that, under existing legislation, it might be possible that some local electric and direct-use projects might be on-stream by year 2000 or 2015. (The legislative mechanism is not provided.) We speculate here, that if the competitive exploration milieu seeks the large high-value targets, they will inevitably discover lower grade and smaller targets as well. Momentum and a set of skills will develop and will be further applied in the search for, and development of, small, specific-use geothermal resources near thermal demands. Hence we anticipate that by 2000, or 2015, perhaps more than a dozen local electric and direct-use schemes will be in stages of design, construction, production, or upward expansion.

8.0 RECOMMENDATIONS

8.0. RECOMMENDATIONS

8.1. Changes to Foster Exploration and Development

Our strongest recommendation is that the provincial government take the lead in fostering exploration and development of geothermal resources by encouraging participation by the private sector. A discussion of the means and impact of this course of action is given in Section 7.5-7.7 and in Appendix I.

8.2. Research

A secondary recommendation which can be implemented independently is to accelerate applied research and development. Certain government-sponsored scientific and engineering services are a traditional part of the economy of Canada.

Current Work in Canada

Jessop (1975) outlined the institutional procedure for geothermal research and development within the federal government sphere. Earth Physics Branch (EPB) of Energy, Mines and Resources (EMR) is the lead agency. Within EPB's Division of Seismology and Geothermal Studies, a group called Geothermal Service of Canada has been created. EPB interfaces and coordinates with the Geological Survey of Canada and the Energy Policy Sector; both are also agencies within EMR.

To date, practical geothermal energy studies have been conducted on the projects previously mentioned:

1. studies at Meager Creek, B.C.

2. contribution to federal-provincial funding of B.C. Hydro's exploration at Meager Creek
3. studies at Mt. Cayley, B.C.
4. inventory of thermal springs in B.C., the Yukon, and NWT
5. studies of Prairie Basins
6. financial support of the University of Regina Well
7 heat-flow drill holes and studies in various places in Canada.

"The National Energy Program, 1980" (EMR, 1980, p. 74) combines geothermal energy studies in a general category with solar, biomass, wind and hydraulic (hydroelectric) energy, under a "Renewable Energy Resources Program". The National Research Council administers solar, biomass and wind studies, each of which is funded to a greater extent than geothermal studies.

EMR administers geothermal studies, which are budgeted at about $730 000 for fiscal year 1981-82, not including overhead or charges for staff researchers. The budget for fiscal year 1982-83 (April 1982 through March 1983) is expected to be about the same.

Government Support in the U.S.

The U.S. Geological Survey (USGS), under the Department of the Interior, conducts regional and specific geologic mapping, and applies physics and chemistry to various geologic research problems, in the same manner as the Geological Survey of Canada.

The USGS's geothermal research programs grew during the 1970's to a peak of about $10-million in the budget for fiscal year 1980 (October 1979 through September 1980). Activities sponsored were:

1. national and regional resource inventory
2. exploration and assessment technology
3. resource characterization
4. geologic controls of subsurface porosity and permeability
5. geoenvironmental effects of production of geothermal energy.

In FY 1981 the budget was contracted to $8-million, as many outside research contracts were completed. The administration's proposal for FY 1982 will leave the geothermal budget with $5.5-million. This is expected to be approved by the U.S. Congress.

The budget of USGS's Conservation Division, which classifies federal lands for leasing, is not included in the amounts given above.

The Department of Energy (DOE) is the successor to Energy Research and Development Administration (ERDA), which absorbed the Atomic Energy Commission.

DOE's fiscal year 1981 budget was US $152-million. It was distributed among the following programs:

1. hydrothermal resource studies (35%)
2. hydrothermal commercialization (7%)
3. geopressurized resources (23%)
4. geothermal technology development (35%)

The administration's proposal for FY 1982 is subject to austerity measures currently in progress and is $46-million. It is not known whether the U.S. Congress will approve the proposal or substitute a lower figure.

Several DOE subprograms include resource definition and development of materials, equipment and technology. DOE is the major supporter of the developmental research described for various institutions in Section 2.5.

The "Geothermal Energy Research, Development, and Demonstration Act of 1974" established the mechanism for loan guarantees of up to 75% of all capital costs for development (Nasr, 1978; Bromberg, 1980), including exploration in development costs. Authorization is up to US $100-million per project. Status of the program* is that five projects totalling US $93-million in borrowings have been approved, and US $511-million are in process. The Bank of Montreal (California) is one of the principal lendors under the Geothermal Loan Guaranty Program (Woods, 1980).

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*As of November 1980.

In 1980 DOE announced a "User-Coupled Confirmation Drilling Program", a cost-sharing program. DOE will provide 20% of costs of reservoir confirmation drilling if the program is successful, and up to 90% if unsuccessful. There are several criteria, the leading being that a distinct direct-use project must be feasible if the geothermal resource is confirmed.

Governments of the western states have promulgated leasing laws for state lands and procedures for all lands (see Wonstolen, 1980; Sacarto, 1980), and have directed their geological divisions to proceed with appropriate research (see Schuster and Korosec, 1980). Geologic efforts generally include mapping around thermal springs and in volcanic terranes, geochemistry of thermal springs, and shallow temperature gradient wells. This work is generally identical to reconnaissance exploration (Appendix D), except that results are published for the benefit of industry and the state's constituents and planners.

8.3. Recommendations for Provincial Government Work

We suggest a three-level program be undertaken by the Province of British Columbia. The three levels are concerned with resource evaluation, resource application, and financial assistance.

Resource evaluation does not mean that the government should undertake exploration, but that it might begin to acquire and maintain a data base available to the public. This type of work is customarily practised in the sectors of oil and gas, coal, metals, and non-metallic minerals. The scientists, engineers, and administrators in the Ministry of Energy, Mines and Petroleum Resources should become informed on geothermal activity elsewhere in the world; we suggest that the first program would be to establish liaison with extraprovincial workers.

Ministry geologists customarily acquire regional information in the area of metal and coal deposits, as a service to the public and as an aid in planning. One of the programs currently in existence is a computerized record keeping system for metal deposits called "MINFILE". We suggest that the Ministry undertake geologic studies in prospective geothermal areas and adapt the MINFILE programs to accommodate a separate geothermal data bank, with information deriving from all sources.

We suggest specific research studies aimed at evaluating hydrothermal resources, resources suitable for direct use, and resources which might occur in remote sites.

Study of applications would provide for liaison with extraprovincial workers and for specific studies in British Columbia which would parallel certain resource evaluation studies. A good candidate for study involves the evaluation of geothermal energy for alumina reduction, such as one completed recently by Battelle in the U.S. (Davis, 1980). Determination of thermal demands might be made for communities in southeastern B.C. and for communities in remote sites near prospective geothermal resources.

It may be appropriate for the provincial government to study its role in financial assistance for geothermal resource development, once exploration and development policy is established. It would be consistent with other governmental services for British Columbia to consider underwriting or spreading the risk, particularly with community heating systems or with community-sponsored local electric systems.

APPENDIX A. PHYSICAL UNITS AND CONVERSION TABLES

TABLE A-1. Quantities and Units in General Use in Geothermal Work

Quantity	SI Units	Symbol	Other traditional units
length	meter, kilometer	m, km	inch, foot, mile
area	square m, hectare	m^2, ha	square inch, acre
volume	liter	L	gallon , cubic feet
mass	kilogram	kg	"pound"
time	second	s	-----
fluid flow (mass)	kilograms per hour	kg/h	"pounds"/hour
---- (volume)	liters per second	L/s	gallons/minute, cubic feet per second (cfs)
temperature	degree kelvin	K	degree fahreheit, degree celsius
force	newton	N	pound
pressure	pascal	Pa	pound-per-square-inch (psi), -gauge (psig), or -absolute (psia), kg/cm^2, bar, atmosphere, inches of mercury
energy (thermal, mechanical)	kilojoule	kJ	horsepower-hour , newton-metre , Btu, calorie
------ (electrical)	kilowatt-hour	kWh	-----
enthalpy (specific heat)	kilojoules/kilogram	kJ/kg	Btu/pound, calories/gram
power (thermal, mechanical)	kilojoules/second	kJ/s	horsepower, Btu/hour
----- (electrical)	kilowatt	kW	-----

TABLE A-2. Conversion Tables for Common Units (continued)

VOLUME

Original Unit		To convert to ...			
		cubic feet (cf)	gallons, Imp.	gallons, U.S.	Litres (L)
cubic feet (cf)	multiply by	1	6.227 9	7.480 5	28.32
gallons, Imp		0.160 57	1	1.200 96	4.545 6
gallons, US		0.133 7	0.832 67	1	3.785
litres (L)		0.035 31	0.219 99	0.264 20	1

FLUID FLOW (volume or mass/unit time)

Original Unit		To convert to...					
		L/s	gal Imp/min	gal US/min	cfs	lbs/hour	kg/hour
litres/second (L/s)	multiply by	1	13.200	15.852	0.035 31	* 7 938	* 3 600
gal Imp/min		0.075 76	1	1.201 0	2.676 x10^{-3}	* 601.4	* 272.7
gal US/min		0.063 08	0.832 7	1	2.227 x10^{-3}	* 500.7	* 227.1
cubic feet/sec (cfs)		28.32	373.8	448.9	1	* 224.8 x10^{3}	* 102.0 x10^{3}
lbs/hour		* 126.0 x10^{-6}	* 1.663 x10^{-3}	* 1.997 x10^{-3}	*4.449 x10^{-6}	1	0.453 5
kg/hour		* 227.8 x10^{-6}	* 3.667 x10^{-3}	* 4.404 x10^{-3}	*9.809 x10^{-6}	2.205	1

* Applies only for water at a density of 1 kg/litre

PRESSURE (force/unit area)

Original Unit		To convert to....						
		atm	bar	kg/cm^2	kPa	psi	inches of mercury	feet of water
atmosphere (atm)	multiply by	1	1.013 25	1.033 3	101.325	14.696	29.921	33.957
bar		0.986 92	1	1.019 8	100	14.504	29.530	33.513
kg/cm^2		0.967 77	0.980 66	1	98.059	14.222	28.957	32.863
kilopascals (kPa)		9.869 x10^{-3}	0.01	10.198 x10^{-3}	1	0.145 04	0.295 30	0.335 13
lbs/in^2 (psi)		0.068 05	0.068 95	0.070 31	6.894 7	1	2.036	2.310 6
inches of mercury (at 0°C)		0.033 42	0.033 86	0.034 53	3.386	0.491 16	1	1.135
feet of water (at 20°C)		0.029 45	0.029 84	0.030 43	2.984	0.432 79	0.881 15	1

TABLE A-2. Conversion Tables for Common Units (concluded)

ENERGY

Original Unit		To convert to...				
		calories	Kg/Calories	kj	kwht	Btu
calories (gram)	multiply by	1	0.001	4.186×10^{-3}	1.163×10^{-6}	$3.968\ 5 \times 10^{-3}$
Calories (kg)		1 000	1	4.186	1.163×10^{-3}	3.968 5
kilojoule (kj)		238.9	238.9×10^{-3}	1	277.78×10^{-6}	0.948 05
kilowatt-hour, thermal (kwht)		859.8×10^{3}	859.8	3.6×10^{3}	1	3.413×10^{3}
Btu		251.984	0.251 984	1.054 8	293.06×10^{-6}	1

MISCELLANEOUS UNITS

To convert . . .	into . . .	multipy by
meters	feet	3.281
kilometers	miles	0.621
millimeters	inches	0.039 4
kilojoules/kilogram	Btu/pound	0.429
hectares	acres	2.471
kilograms	pounds (mass)	2.205
years	hours	8760
kilowatts	kilojoules/hour	3600
degrees celsius	degrees kelvin	add 273.5
degrees celsius	degrees fahrenheit	multiply by . . . then add 1.8 32

APPENDIX B. GEOLOGIC AND GEOTHERMAL TERMS

TABLE B-1. Abbreviated Geological Time and Rock Scale and Nomenclature

Time:	Era	Period	Epoch	Radiometric dates (in millions of years)
Rock:		System	Series	
	Cenozoic	Quaternary	Recent Pleistocene	1.5
		Tertiary	Pliocene Miocene Oligocene Eocene	70
	Mesozoic	Cretaceous Jurassic Triassic		200
	Paleozoic	Permian Pennsylvanian Mississippian Devonian Silurian Ordovician Cambrian		600
	Precambrian			

GLOSSARY

anhydrous - literally "without water", used to denote minerals with less water in the crystal structure as distinct from those with more, viz. micas and clays, respectively.

anion - a negatively charged ion or complex, such as chloride (Cl^{-}), sulfate $(SO_4^{=})$, carbonate $(CO_3^{=})$; common in geothermal waters.

anomaly - a geophysical measurement or group of measurements which depart from a norm; may have positive or negative values with respect to the norm ("high" or "lows"); methods used may be thermal surveys, electrical resistivity surveys, gravity surveys, etc., hence "thermal anomaly", "resistivity low", etc.; anomalies are found to be related to subsurface geologic features.

aquifer - a porous and permeable rock unit which serves as a natural watercourse, and from which water can be withdrawn.

brine - any natural water containing dissolved solids or salts; includes ordinary groundwaters and geothermal waters.

chalcedony - a solid, amorphous form of silica; common in deposits from active and past thermal springs.

calcium carbonate - as a solid, the minerals calcite and aragonite; also a common dissolved solid in geothermal waters, $CaCO_3$.

cation - a positively charged ion, such as calcium (Ca^{++}), sodium (Na^{+}), potassium (K^{+}); common in geothermal waters.

diorite - an intrusive rock made up mainly of calcium feldspar and hornblende or other dark minerals.

dome - (1) a volcano formed where a viscous body of lava has extruded onto the surface and, instead of flowing downhill, has expanded or puffed out slightly or not at all; (2) an uplift which has resulted in beds of overlying sedimentary rocks dipping away from the center.

enthalpy - the heat content per unit weight of a substance at a given temperature; also "specific heat"; at higher temperatures, a portion of the enthalpy may be extracted and used.

envelope - a geologic zone which circumscribes another zone; as used in Section 3.0, a zone of unknown geothermal potential around the outside of a zone believed to have high potential.

facies - a zone distinct, as to composition, in a horizontal direction, within a sedimentary rock unit; facies change - a change in composition laterally within a unit, e.g. from limestone to shale, from shale to sandstone, etc.

fault - a fracture in rocks along which movement has taken place of one wall relative to the other; faulting - the process of rupture and differential movement by which faults are formed; smaller faults may be a few hundred meters long, with displacements of a few meters; larger faults may be many hundreds of kilometers long and have a few hundred km displacements; fault surfaces may be tight cracks, or may be occupied by voids, clayey groundup rock, or mineral veins.

feldspar - a common mineral of varying proportions of potassium, sodium and calcium, with alumina and silica; several varieties; prominent in the granitic rocks.

fold - a type of deformation of rocks (due to tectonic stresses) which results in bending; best displayed by sedimentary rock beds or metamorphic rock layers.

greywacke - a sandstone composed of abundant fine volcanic debris and some shaly material; generally dark in colour and poorly sorted.

intrusive rocks; intrusives - rocks, such as granite, syenite, monzonite, granodiorite, etc., which crystallize deep in the earth's crust, from a magma; subvolcanic instrusives - such rocks underneath a volcano, both having derived from the same molten rock and mechanism of emplacement.

lava - molten rock or magma which is erupted onto the surface to form volcanos or sheets of volcanic rocks; sometimes loosely applied to include the rocks themselves after they crystallize and harden; the physical properties of lava differ from magma in that gases boil off, viscosity is sometimes higher; the volcanic rocks which form from lava are called rhyolite, latite, dacite, andesite, basalt, etc., depending on composition.

lithostatic pressure - a confining pressure, deep below the surface, which exceeds that which would be exerted by a column of water or brine (hydrostatic pressure); it is essentially the weight of the overlying rocks and may approach 2.7 times the hydrostatic pressure at that depth.

magma - molten rock, generally in a distinct body deep in the earth's crust; may erupt as "lava" or may crystallize as any one of a number of "intrusive" rocks, granite, syenite, granodiorite, or diorite, the name depending upon composition and form.

mantle - the layer of material underlying the earth's crust and overlying the core; composed of magma and plastic rocks rich in iron and magnesium.

metamorphic rocks - rocks whose texture and mineral composition are changed by high temperatures and high pressures acting over a period of time; metavolcanics - metamorphic rocks which were originally a volcanic rock; metasediments - metamorphosed sedimentary rocks; examples: greenstone (from andesite or greywacke), marble (from limestone), schist (from shale).

permeability - the measure of the ability of a fluid to move within a porous rock unit, a function of the degree of interconnection of pore spaces; in fracture controlled geothermal reservoirs permeability can be erratic and its measurement difficult to extend by calculations.

plutonic - same as "intrusive", persisting from ancient nomenclature for rocks believed to come from fire (plutonics) or from the sea (neptunic rocks).

porosity - the relative amount (or percent) of pore spaces within a rock unit.

quartz monzonite - an intrusive rock made up of two feldspars, quartz, and minor dark minerals such as biotite mica, differing from granite only in higher sodium-calcium feldspar content.

retrofitting - re-fitting; as used in Section 6.0 and Appendix G, the installing of a geothermal heating system in existing buildings or plant, after removal or rebuilding of the previous system.

rift zones - one of three types of discontinuity in the plate tectonics system (see also subduction, transform fault); where oceanic crust moves apart continuously as submarine volcanic activity forms new crust; the Mid-Atlantic Ridge, upon which Iceland lies, and the East Pacific Rise, off the B.C. coast, are two such rift zones.

schist - a metamorphic rock characterized by an abundance of mica and a leafy texture.

silica - silicon dioxide (SiO_2), as a mineral, amorphous solid or dissolved in thermal waters; quartz - one of the most common of all minerals, made up of silica; chalcedony - a common amorphous solid of silica, one variety of which is opal.

subduction zones - one of three types of discontinuity in the plate tectonics system; the plunging of oceanic crust under an overriding plate of continental crust; ongoing at present along western South America, the Aleutian Islands, Japan, etc.; volcanos are present inland from subduction zones, as well as other places.

tectonism - the process of major geologic change: mountain building, lateral movements of large crustal plates, and folding and faulting of rocks; tectonic belt - a zone of past or present activity or disturbance; plate tectonics - the system of past and present movements of units of oceanic and continental crust.

terrane - a region or belt characterized by a distinct assemblage of rocks and geologic structures; e.g. a "volcanic terrane".

transform fault - a rupture in ocean crust, with lateral displacement, owing to differential movement between two adjacent "plates"; part of the system of rifting, subduction and continental drift; the Queen Charlotte - Fairweather Fault is a transform fault.

tuya - a central volcano which erupted underneath glacial ice; sides were contained by a chilled lava margin or the ice itself, and the pile was built up to have a flat, level top.

APPENDIX C. NATURAL GEOTHERMAL SYSTEMS

C. NATURAL GEOTHERMAL SYSTEMS

C.1. Basic Classification

Geothermal systems are generally classified according to common characteristics of temperature, pressure, depth, fluid composition and type of host rock or reservoir. A classification adapted to British Columbia might be:

1. Hydrothermal Convection Cells
    - a. Steam-dominated
    - b. Hot water-dominated
2. Gradient Heat
    - a. Sedimentary basins
    - b. Geopressurized basins
    - c. Deep circulation, including Rocky Mountain systems
3. Igneous-related systems
    - a. Hot dry rock
    - b. Plastic or molten magma.

The general position, relative to temperature and fluid pore pressure, of the various types of geothermal resources are indicated in Drawing C-1. The patterned

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Drawing C-1 follows

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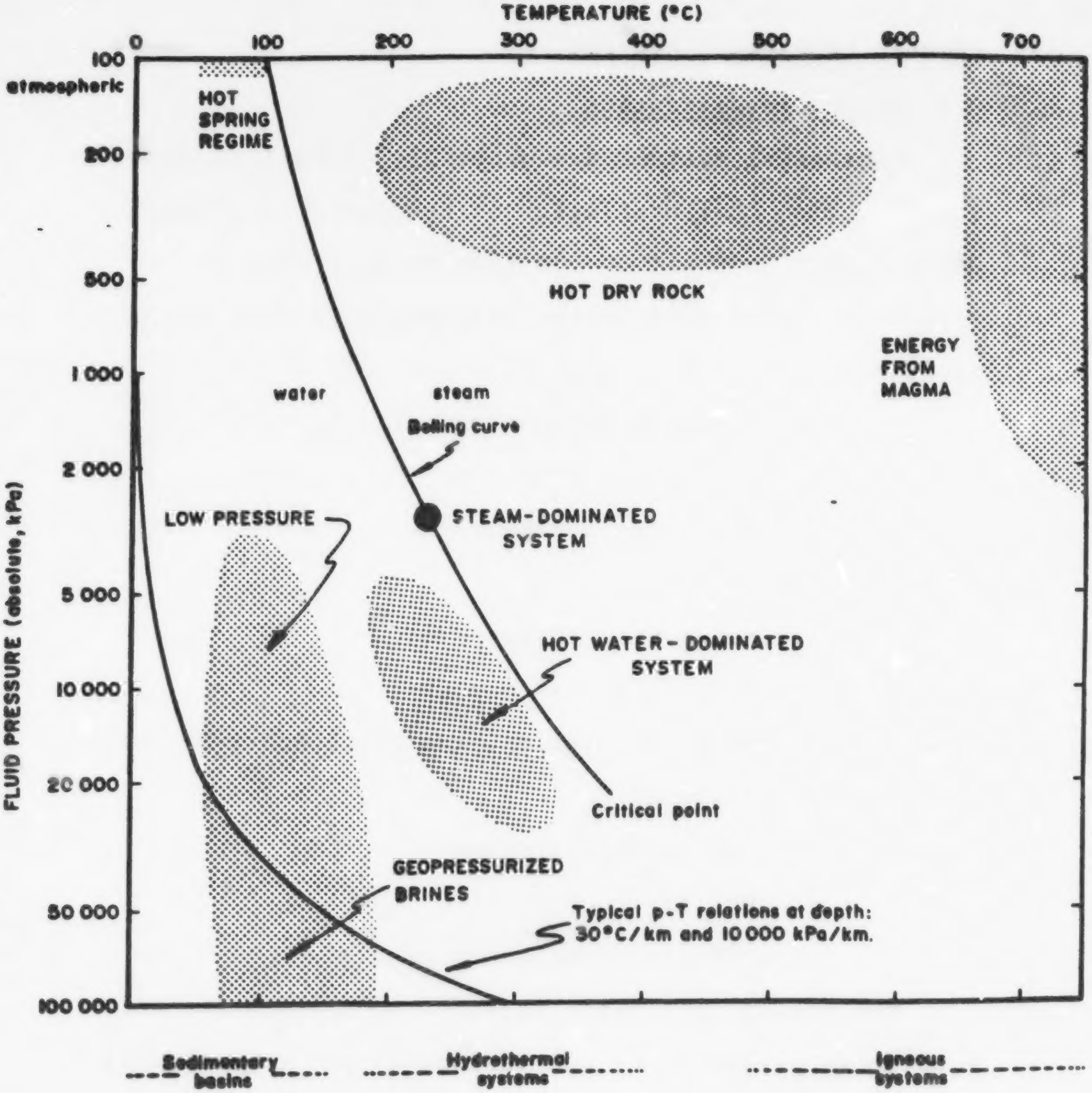
areas in the drawing enclose typical deposits which are



DRAWING C-1

TYPES OF GEOTHERMAL RESOURCES SHOWN AS GENERALIZED FIELDS ACCORDING TO SUBSURFACE TEMPERATURE AND FLUID PRESSURE IN NATURAL STATE under study or under utilization. In actual fact, the different types of deposits overlap in their pressure-temperature conditions, rather than being separated into distinct fields as shown.

Drawing C-1 generalizes some rather complex phenomena. For example, the pressure-temperature gradient line (on the left) is based on a typical geothermal gradient in continental crust, of about 30°C/km, and a typical fluid pore pressure gradient of about 10 000 kPa/km (100 kg/cm^2km). The resultant depth-dependent gradient, 10 000 kPa/30°C, might be considered normal, but actual pressure and temperature gradients vary considerably in regions of the geothermal deposits classified above.

C.2. Relationship with Thermal Springs

Thermal springs are the most obvious and noticeable surface manifestation of underlying geothermal resources, and they tend to stimulate the observer's curiosity and imagination about the sub-surface. Thermal springs commonly build up tufa mounts--calcium carbonate, silica minerals, and various salts--and they often bubble with gases such as carbon dioxide, and minor amounts of methane, hydrogen sulfide, and sulfurous-smelling compounds.

Although thermal springs are not the principal concern in geothermal studies, some discussion of their relationships with underlying reservoirs is necessary. Two major classes of thermal springs are presently known to exist in British Columbia.

The vast body of geothermal heat--that consistently stored in the upper part of the earth's crust (Sections 1.0 and 2.0)--has very few surface manifestations. Wherever surface water percolates into the ground to depths of more than a few hundred meters and spends enough time in transit or in residence to reach the same temperature as the surrounding soil or rock, the result is a geothermal system, however low temperature it might be. If the water flows to the surface (rapidly enough so that it does not lose all of its acquired heat) the result is a warm spring, or at least a spring having a more seasonally stable temperature than surface waters.

Rocky Mountain Hot Springs. The Rocky Mountain geothermal and hot springs systems are a large scale example of such circulation. The example at Banff, Alberta (given number 820-1 in this report) discharges from the Sulphur Mountain Fault (Drawing C-2) at temperatures as high as 47°C. Because of the covariance of flow rates and temperatures with seasonal changes and periods of drought, there appears little doubt that the source of

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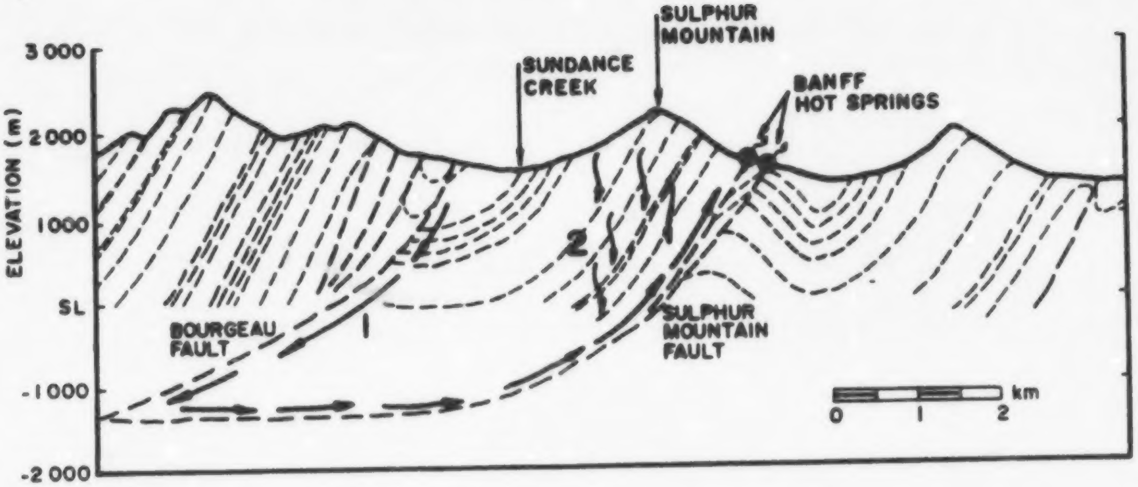
Drawing C-2 follows

- - - - - - - - - - - -


3 000
2 000
1000
SL
-1000
-2 000
ELEVATION (m)
SULPHUR MOUNTAIN
SUNDANCE CREEK
BANFF HOT SPRINGS
2
1
BOURGEAU FAULT
SULPHUR MOUNTAIN FAULT
0
1
2
km

DRAWING C-2

EXAMPLE OF ROCKY MOUNTAIN GEOTHERMAL SYSTEM AND HOT SPRING

Banff, Alberta (820-1). Recharge according to Haites (1), and van Everdingen (2).

the thermal water is ordinary surface and groundwater and that transit time is about 2.5 months. The source is postulated as Sundance Creek (Haites, 1959) or Sulphur Mountain (vanEverdingen, 1972). The geothermal gradient in this region is broadly inferred as 20°C/km, or slightly less than the continental average (AAPG, ca. 1973). In general, Rocky Mountain hot springs imply deep circulation of water--to a depth of about 2.5 km in this instance--not necessarily an anomalous heat reservoir high in the earth's crust. Drawing C-3 illustrates this phenomenon (path 'A') in the context of other types of geothermal systems.

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Drawing C-3 follows

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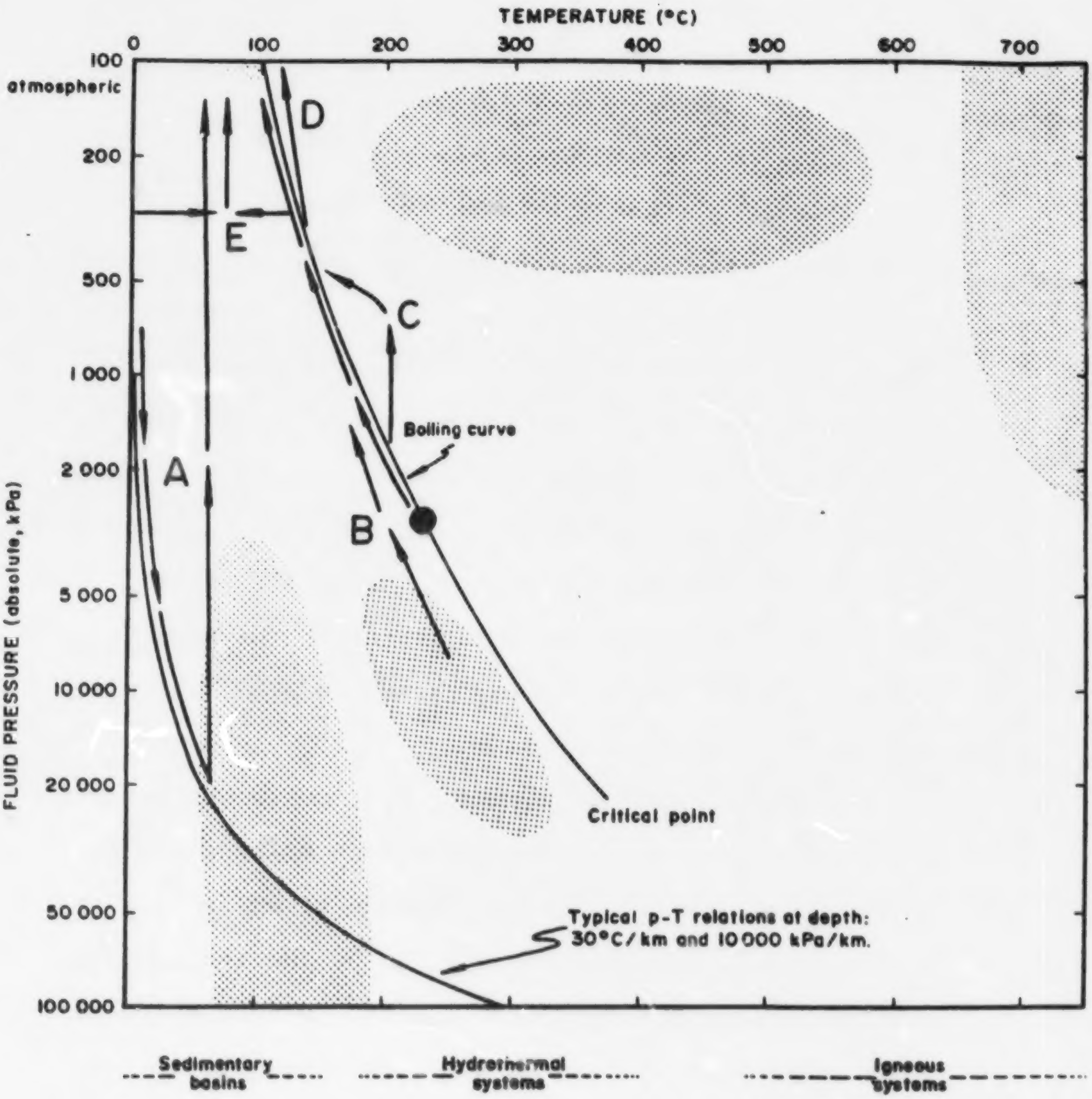
Where geothermal water continually circulates through the system and escapes upward through an open fault surface, it flows because of a slight hydrological gradient. This difference in pressures between the recharge and discharge points derive from differences in elevation of the two points, and from a slight reduction in density in the discharge side owing to the elevated temperature.

Hydrothermal Systems. Hydrothermal systems are deposits of water, steam or brine heated and circulated by underlying hot magma (Drawing C-4). Hot springs from



DRAWING C-3

FORMATION OF HOT SPRINGS:

A – Rocky Mountain type;
B – subsurface leaks from hydrothermal;
C – subsurface boiling and condensing;
D – geyser;
E – mixing with cool groundwater.

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Drawing C-4 follows

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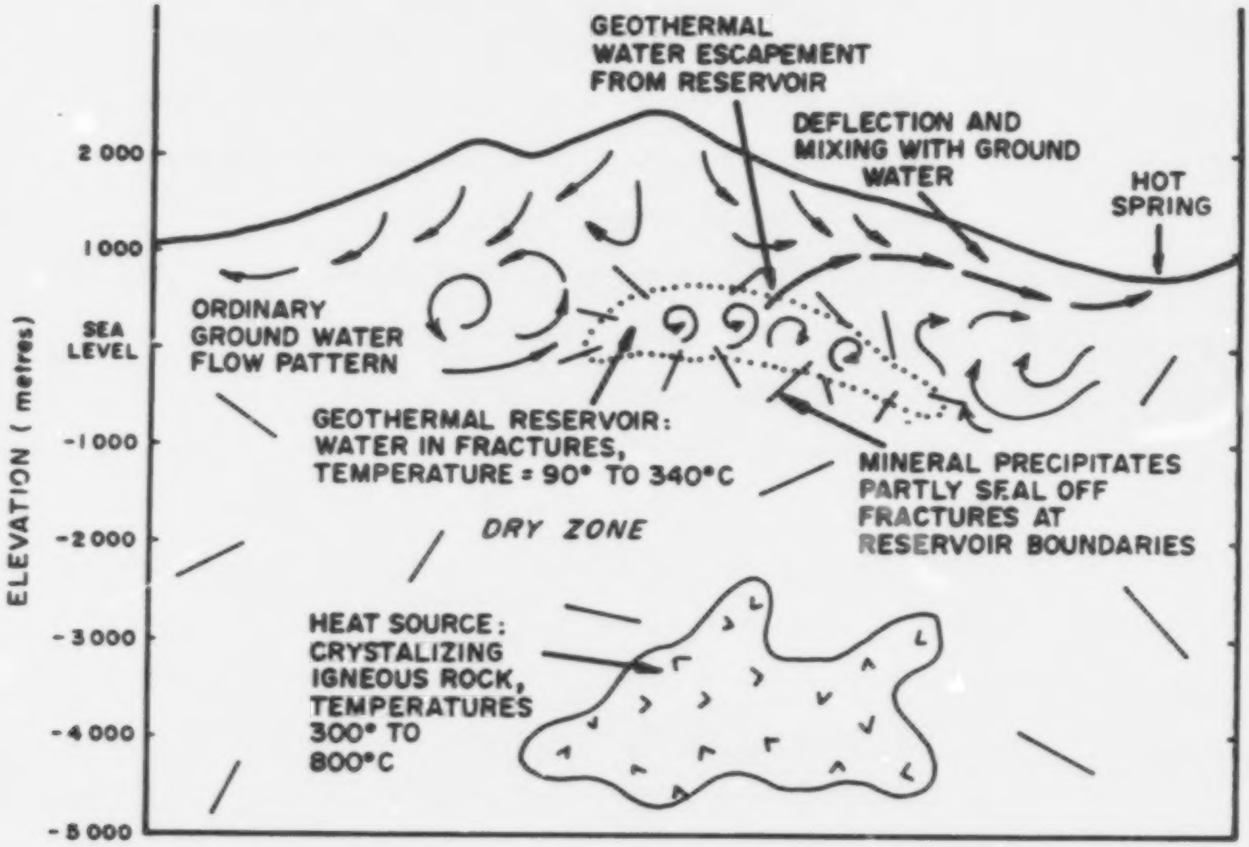
hydrothermal systems are leaks from a semi-sealed reservoir system whose internal pressure and temperature are controlled by complex reactions. The initial escaped fluid is at a high temperature, as shown by the broad path 'B' on Drawing C-3. As the fluid ascends, it may give off heat to the surrounding rocks, staying beneath the boiling curve, or it may boil in the subsurface (and later condense) as shown by path 'C'. If boiling takes place near the surface (path 'D') the result is a geyser. There are no known geysers in B.C. The mixing phenomenon is far more common.

As the escaped geothermal water nears the surface it encounters cooler ground water and mixes along the paths shown as 'E'. The temperature of any resultant hot spring is the weighted average of the temperatures and amounts of the component fluids. Direct evidence from geothermal studies in B.C. and elsewhere in temperate and rainy climates suggests that this happens commonly, repeatedly and continually.

Understanding of this process and its prevalence in nature produces two corollaries:

1. the observed temperature of a hot spring is of little value by itself in deducing the


GEOTHERMAL WATER ESCAPEMENT FROM RESERVOIR
DEFLECTION AND MIXING WITH GROUND WATER
HOT SPRING
2 000
1 000
SEA LEVEL
-1 000
-2 000
-3 000
-4 000
-5 000
ELEVATION (metres)
ORDINARY GROUND WATER FLOW PATTERN
GEOTHERMAL RESERVOIR: WATER IN FRACTURES, TEMPERATURE = 90° TO 340°C
MINERAL PRECIPITATES PARTLY SEAL OFF FRACTURES AT RESERVOIR BOUNDARIES
DRY ZONE
HEAT SOURCE: CRYSTALIZING IGNEOUS ROCK, TEMPERATURES 300° TO 800°C

DRAWING C-4

REPRESENTATIVE MODEL OF HYDROTHERMAL CONVECTION CELL temperature or extent of the underlying reservoir; and

2. in all probability, most escapements of hydrothermal waters are diluted by cool groundwaters to the extent that they are unrecognizable; the cool water overwhelming the thermal water by its greater volume and incorporating the thermal plume in its normal down-basin flow toward a river or lake.

Hydrothermal reservoirs can exist without forming superjacent hot springs. Hot springs are of interest to the explorer in that chemical evidence can be obtained from them as to the character of the underlying system (see Appendix D); however, they are incidental features.

C.3. Hydrothermal Convection Cells

The term "hydrothermal" has been used for more than a century, usually with reference to metallic ore deposits which were deposited by circulating hot waters and water vapours. "Hydrothermal" has just recently been applied to that number of geothermal systems of a similar nature. There are four basic natural requirements for the occurrence of an active hydrothermal system. These are:

1. a source of high temperature heat
2. porosity and permeability sufficient for water to circulate within the system

3. the presence of water or a water-vapour mixture
4. the existence of an impermeable or semi-permeable seal, particularly above and on the sides of the reservoir.

The heat source for most hydrothermal systems is a chamber of magma or lava, which occupies a spot generally within five or ten kilometers of the earth's surface (Drawing C-4). This body may have been recently emplaced, or emplaced within the last five million years. The temperature of tne igneous mass upon emplacement was probably at or near the melting point for such rocks, about 650-800°C. The magma body derived from melting at a depth on the order of 30-50 kilometers beneath the surface and gradually bobbed upward in response to density differences and stresses within the earth's crust.

At the time of our observation of the geothermal system, the magma body may have been emplaced for a period of time and may have cooled to a semi-solid or plastic state. It may even have hardened into crystalline rock. The important factor is that its temperature is sufficient to supply heat to a circulating hot water or water-stream system. The temperature of that system may range up to 350°C.

There are several geologic types of hydrothermal reservoirs known. Since such systems tend to occur in active volcanic terranes, they tend to form in the rocks characteristic of those terranes. Many occur in very porous and permeable tuffs, a fragmental volcanic rock which can have up to 30% pore space. Cerro Prieto, Mexico; Olkaria, Kenya; and several of the fields in New Zealand and in the Imperial Valley, California, are of this type. The reservoir at The Geysers, California, occupies a greywacke; in this instance, a tight sedimentary rock having no inherent porosity between grain boundaries, but which is fractured to the extent that it exhibits high secondary permeability. Other reservoirs occupy long, slender, and interconnected fracture systems in granitic rocks which are otherwise tight and permeable. Such fields are the Roosevelt Field, Utah, Dixie Valley, Nevada, and probably parts of the Meager Creek geothermal field.

The presence of water in pore spaces and interconnected fractures in the reservoir rock is what distinguishes active hydrothermal systems from bodies of 'hot dry rock' (Section C.5). In extremely arid areas of the world water may be absent because of lack of adequate supply. Bodies of tight impermeable rock lack water because none can search the unit. The climate, rainfall, and snow pack in British Columbia lead to a generally abundant supply of groundwater. We expect that future work there will encounter no problems owing to lack of supply.

In order for a high energy hydrothermal reservoir to develop, some sort of restrictions must first develop on the flow of fluid between the reservoir and its surrounding environment. The principle of such reservoirs is that heat is supplied near the base; it is transferred upward by convecting fluid; and it is released through the top of the system by conduction and by convection of low temperature groundwater. Heat accumulates within the system, and the temperature of both rock and the pore space fluid rises to find its own equilibrium level.

In a system which is thoroughly open, with no barriers to fluid flow, whatever water flows into the system simply boils away at once, and equilibrium is maintained at a low pressure anhydrous state. Similarly, where fluid is flowing through the system laterally at a high rate, it simply robs and dissipates the heat, experiencing only a slight increase in temperature in transit.

In some instances part of the impermeable seal or the barrier to fluid flow is a tight rock unit such as a shale or a serpentine. For the most part, however, the seal has a way of forming by itself during the early life of the system. Hydrothermal waters are generally rich in dissolved silica. As the water circulates outward in the system and cools, the silica becomes less soluble and tends to precipitate as chalcedony or quartz within the passageway fractures, thus restricting or sealing off fluid flow. Similarly, ordinary groundwater generally contains some dissolved calcium carbonate. As the groundwater circulates toward a geothermal system it becomes warmer; the calcium carbonate becomes less soluble, and is precipitated within fractures as calcite. With time, then, hydrothermal systems tend to isolate themselves and establish their own regimes of pressure and fluid flow.

Steam-Dominated Systems. A steam-dominated system is the highest-yield commercial type of hydrothermal resource. It has the capability of producing a dry super-heated steam and is commonly called by the name of its produce, "dry-steam system".

The most definitive work to date on steam-dominated systems is by White, Muffler, and Truesdell (1971). Drawing C-5, adapted from that paper, is a pressure-enthalpy diagram showing the same general field as those shown for hydrothermal systems in Drawings C-1, C-3, and C-6.

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Drawing C-5 follows

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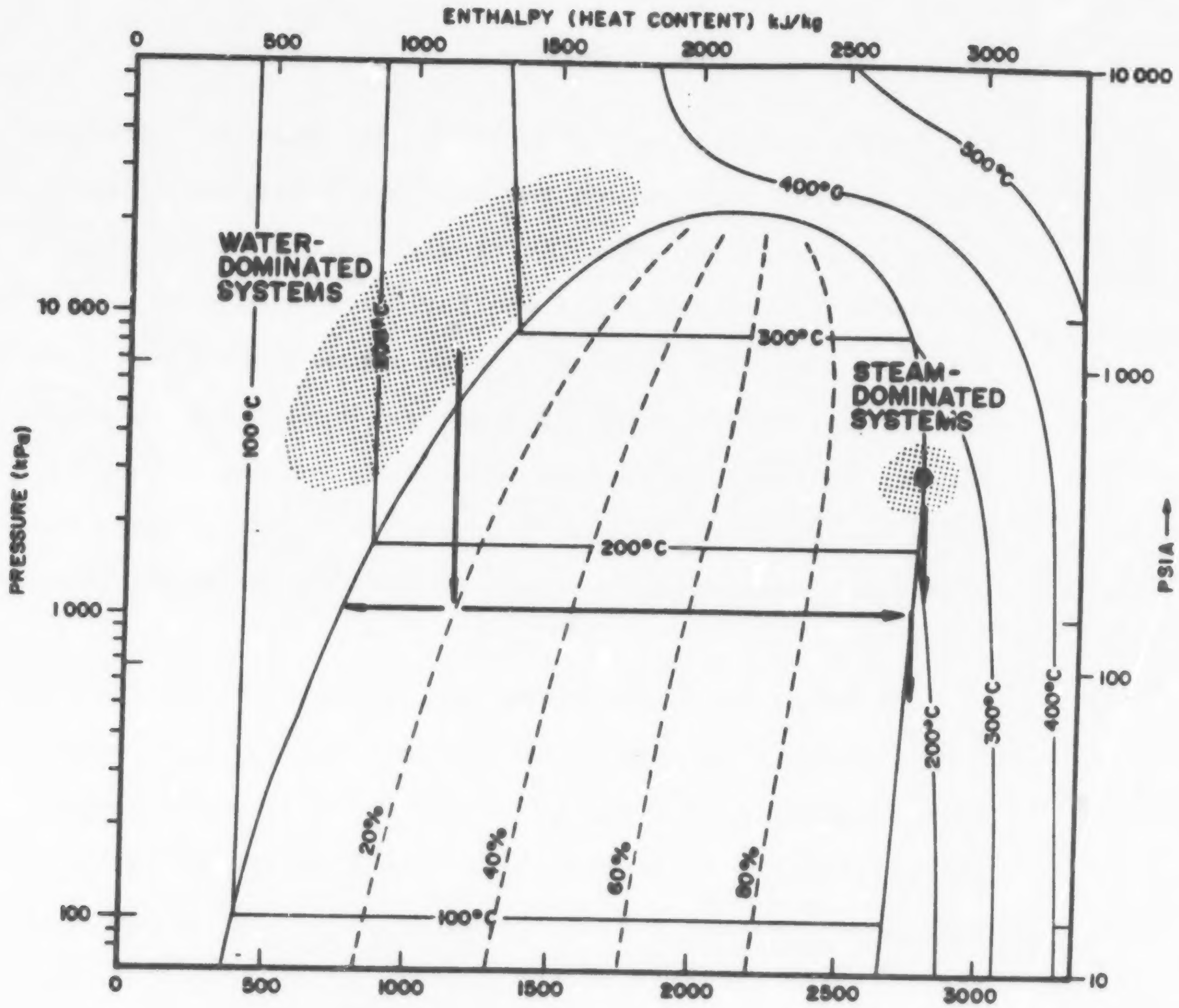
Steam-dominated hydrothermal systems tend to form under the unique pressure, temperature and heat-content the geothermal gradient peculiar to the region. Secondly, the discharge temperature and heat are functions of the volume and velocity of water flowing through the system. The mechanism is described whereby descending cold water takes on heat from the surrounding rocks (Appendix C.2.) and upon ascending gives up some heat to its surroundings. Sooner or later equilibrium is reached and the flow (which might or might not vent as a thermal spring) develops a consistent temperature pattern or seasonal range of temperatures.

The specific heat stored within the rocks surrounding a deep circulation system may be more or less equivalent to the specific heat stored within rocks in a deep sedimentary basin. It is generally less than the specific heat stored within a hydrothermal system. Depending upon the size and strength of the system, we believe that the heat naturally or artificially transported upward past a given point is less than that transportable from an aquifer in a deep sedimentary basin, or from a productive zone in a hydrothermal reservoir. In terms of overall magnitude, we feel that deep circulation systems offer less potential than the geothermal systems previously discussed.

However, deep circulating systems are easily exploited where they are known to exist, and future exploration and development work may intentionally or accidentally



DRAWING C-5

PRESSURE-ENTHALPY DIAGRAM FOR WATER AND VAPOUR, SHOWING PROPORTIONS OF STEAM TO WATER. POINT INDICATES MAXIMUM ENTHALPY OF SATURATED STEAM, 2805 kJ/kg AT 236°C AND 3120 kPa.

conditions shown in the drawing, owing to a slight bulge in the right hand side of this curve. This point represents the maximum possible heat content for water and steam coexisting in equilibrium.

The interconnected voids in a steam-dominated system are filled with small- and large-scale convection cells made up of steam and water. At the base of each cell, water is vaporized to steam by taking on heat; the steam rises, gives up heat at the top of the cell, condenses, and then trickles down the void wall to begin again.

As seen in Drawing C-5, steam-dominated systems exist at about 3400 kPa. They are partially sealed off from the surrounding hydrolical and pressure regime, and are generally "underpressured" in relation to their depth. In the practical sense, this means that most deep steam wells can be choked with water (for control, or for reservoir recharge); and that wells are blown with air to start flowing.

Water-Dominated Systems. Hot water-dominated systems are sometimes known by their product name "wet-steam deposits". The principles are the same for such reservoirs, except that no vapour phase is involved in the circulation and transfer of heat from the base to the top and sides. Generally such reservoirs are "over-pressured", that is their internal fluid pore pressure exceeds that of a normal hydrostatic pressure. The expansion of the fluid upon elevation of temperature, commonly to 1.25 times the volume of cold water (a density decrease to 0.8), the formation of a restrictive seal, and the application of heat all combine to create an internal pressure which pushes against the weight of the overlying rock, that is, it approaches lithostatic pressures.

Internal fluid pressures reach 10 000 kPa or more; this field is shown in the upper left of Drawing C-5.

In commercial applications some points are interesting: Firstly, in order to be distinctly commercial the field needs enough internal pressure to lift a column of water up the well bore and flow at 1 000-4 000 kPa at the well head. Secondly, these pressures are high, but not nearly as high as overpressures experienced in deep drilling in the oil and gas industry, and are generally controllable with standard drilling equipment.

Fluid Flow. Commercial characteristics are discussed in more detail in Section 4.0, but the thermodynamic paths of the fluids from the reservoir to the well head, and from the well head to the end use, are important. The paths of both fluids toward a direct turbine generator are summarized in the following.

In the dry-steam case, the arrows (Drawings C-5 and C-6) show the isenthalpic (no loss of heat) expansion of

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Drawing C-6 follows

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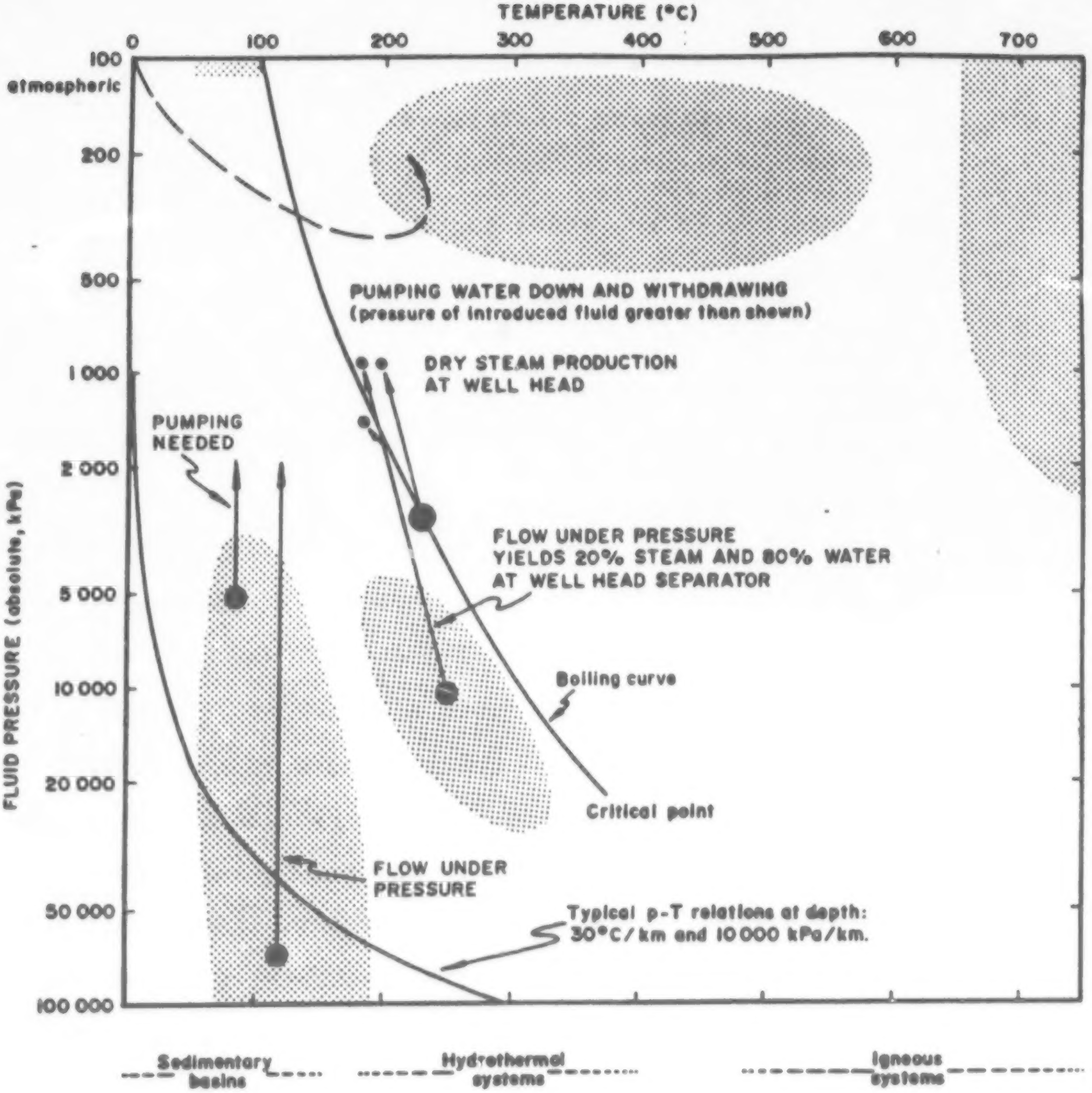
the steam toward the 800-1 000 kPa pressure at the well head. The well head product is 'dry', i.e., it contains no water droplets, and it contains several degrees of superheat. This steam is suitable for direct transmission to the steam turbine, subject to its content of dissolved solids and gases.

The 'wet-steam' case is shown by the inverted 'T'-shaped arrows (Drawing C-5) and the 'Y'-shaped arrow (Drawing C-6). Hot water is allowed to flow up the well bore, through a choke, and into a separating chamber at about 1 000 kPa pressure. Upon exposure to the reduced pressure in the separator a certain fraction of the superheated water flashes instantly into steam, deriving heat of vaporization from the remaining water. Looking at both horizontal arrows in Drawing C-5, the water takes on the properties indicated on the left, and the steam assumes the saturated state shown on the right. In this particular example 20% flashes to steam and 80% remains as water. Drying of the steam to 10-15°C superheat is accomplished by further reduction in pressure as it flows toward the turbine, as shown by the downward pointing arrow on the right.



DRAWING C-6

SCHEMATIC CONDITIONS FOR EXTRACTING ENERGY FROM SYSTEMS SHOWN IN DRAWING C-1

Size, Shape and Depth of Reservoirs. More than 50 active hydrothermal systems around the world have been well studied. They are in production or in advanced stages of exploration. In addition, geologists have studied thousands of hydrothermal metal deposits (fossil systems of the same type) on a systematic basis for several centuries. For example, the trained observer studies the long, thin gold veins at Bralorne, or the circular porphyry copper deposit at Gibraltar, and visualizes the hydrothermal system which existed in each place several million years ago.

Hydrothermal systems can be spherical in shape, long narrow vein-like deposits, or flat tabular blankets. They can be any combination of the various shapes. They can range from a few hundred meters in length to 10 km or more. At a given time a system might extent for 1 000 to 3 000 m in the vertical dimension. The top of the system, that is the top of the commercial zone, may lie as deep as 3 000 m.

As would be expected, the large reservoirs tend to be active over a long period of time, estimated by Smith and Shaw (1979) at as much as 6 million years. The small reservoirs tend to be short-lived.

C.4. Gradient Heat

The second major class of geothermal resource derives its energy from ordinary geothermal gradients.

Although the geothermal gradient varies widely from place to place, the normal value for continents is approximately 25 to 30°C/km. Thus for an area where the mean annual air temperature is about 5°C, rocks and fluids at depths of 2 km have temperatures of 55 to 65°C. The practical aspects of gradient heat are:

1. The total heat stored within ordinary rocks in the continental crust far exceeds the quantity of heat brought close to the surface by volcanic activity;
2. The sedimentary basins and folded sedimentary terranes of the world often include vast rock units which are porous, permeable, and water-saturated. Such units can be many meters thick and can extend over thousands of square kilometers;
3. Water or brine can be extracted or withdrawn from such rocks and the thermal energy utilized;
4. Some specific areas have already been partially explored for oil and gas, and their characteristics are known;
5. Existing oil, gas, groundwater and heat-exchange technology is used to extract this energy;
6. Temperatures are generally lower than those of the hydrothermal systems, often less than 100°C, and thus the principal use of such energy is for space or industrial heat;

7. Because of characteristic low temperatures the energy has a low specific value (in comparison to gas, oil or steam), and it is not transportable for great distances;

8. Most of the problems encountered in application of this energy are not "geothermal" in nature; they are economic, commercial or related to the overall feasibility of the particular application.

The principal points in this section concern the properties of the resource. Utilization is discussed in Section 6.0 and Appendices D, E, G and H.

Sedimentary Basins. Sedimentary basins are widely distributed around the world, on continents and offshore on continental shelves. These are the terranes where oil and gas are found. Thicknesses of sedimentary rocks commonly reach 5 000 m, or as much as 15 000 m in some places, and areal extents measure thousands of square kilometers. The accumulations are characteristically made up of layers of various rock types: evaporites (for example, gypsum and salt deposits), carbonates (limestone and dolomite), shales, sandstones, conglomerates, and mixtures of various types (such as sandy shales). The predominant characteristic is that the rocks are layered (hence "beds" or "strata"), on scales from miscroscopic to tens of meters.

Unless the rocks have been deformed by subsequent folding or faulting, younger rocks overlie older ones. Each of the geologic time-rock units has certain characteristics and this nomenclature (see Appendix B) is universally used to label sedimentary rocks. In a given basin, rocks are further subdivided into distinguishable units, called "formations" or "members", whether they crop out at the surface or exist entirely in the subsurface.

The rocks seldom form perfect tabular layers, however, and many units are lens-shaped. A unit may pinch-out laterally, and it may thicken substantially in the opposite direction. A recognizable rock may persist over a wide horizontal distance, but change composition gradually; for example, from a limestone to a shale. This is an important point, since porosity and permeability may also change. Each compositionally distinct horizontal zone is called a "facies" (e.g. "limestone facies"); and the change is called a "facies change."

Relatively steep-sided features (e.g. salt domes, carbonate reefs) also occur in sedimentary basins, and frequently the rocks have been tilted or folded subsequent to deposition (hence domes, anticlines, synclines).

Oil and gas are found in permeable units in sedimentary basins, generally trapped by overlying and adjacent impermeable units. Saline waters are found with oil and gas. Crystal-clear waters may also flow through aquifers in sedimentary basins.

A geothermal gradient exists everywhere, and a stationary fluid within the rock has the same temperature as its surroundings. Oil is warm or hot at the wellhead, and the deeper the production the hotter the oil. The same is true for water and brine. Use of geothermal resources is concerned with hot water or brine.

Since basins span such a wide range of characteristics, a look at the nature of some current projects should give some indication of resource types.

1. Three U.S. Department of Energy-supported projects are underway in South Dakota, tapping the well-known Madison limestone aquifer of Mississippian age. Well depths range from 640 to 1300 meters and produce water at 41-67°C. Flows range from 11-24 liters per second (L/s); and one project reports 185 kPa (gauge) flowing pressure. Normal solids content of Madison waters is 3 000-10 000 parts per million, including calcium carbonate and sulfate. (Refer to U.S. DOE, 1979, pp. 15, 21-23, 52-55, and Brown, 1979).
2. At Creil and Villanueve la Garenne, in the Paris Basin, France, projects are in progress to heat a total of 5 700 apartment units. Water at

52-60°C is drawn from more than one aquifier at depths of about 1 500 m. Aquifers are several Jurassic and Triassic limestones and sandstones. Dissolved solids are reported as 10 000 at 26 000 ppm in two leading aquifers. One production well has artesian flow of 7 L/s, and when pumped 51 L/s. Spent fluid, at about 41°C is reinjected, taking care that the bottoms of the reinjection wells are 1 km from the production wells to avoid counterproductive cooling of the aquifer.

The geothermal projects started about 1970 by compilation of data from oil wells. (Refer to Jessop, 1976 a,b,c).

3. Energy, Mines and Resources Canada and the Saskatchewan Department of Mineral Resources supported drilling a 2215 m well for a potential space heating application at University of Regina. The well is completed to produce waters from 175 m of the Winnipeg and Deadwood formations, of Cambro-Ordovician age, immediately overlying Precambrian basement.

Production is expected to be 28 L/s of 65°C brine. Dissolved solids are about 10-12%, mainly sodium chloride. Dissolved gas is about 85-130 mL/L at atmospheric pressure, and the gas composition is mainly nitrogen, as much as 2.7% hydrogen sulfide and 4% methane, and traces of helium.

Reservoir properties are considered good: Drawdown is estimated at 131 m after seven years of pumping at a rate of 28 L/s. This will require 66 kW for pumping, about 2% of the 3500 kW (thermal) production. (Refer to Vigrass, 1979.)

To date, sedimentary basins have not been widely developed for geothermal use owing to simple economics. The useable thermal energy contained in a geothermal fluid is about 1/100th or 1/200th the heat of combustion of an equivalent amount of crude oil. Lack of widespread utilization has also been hindered by the site-specific nature of the resource, since a demand for low-temperature heat must exist nearby.

Geopressurized Basins. Extraordinarily high pressures have been measured in some oil and gas fields since about the turn of the century. The mechanism for overpressure is much the same whether the fluid is oil, gas, or brine. The fluid is trapped in the pore spaces of a sandstone, for example, underlying an impermeable shale. The internal or "formation" pressure is independent of ordinary hydrostatic pressure (that pressure which would result from an open vertical column of water or brine), but instead is determined by lithostatic pressure. The fluid essentially supports the weight of the overlying rock.

Overpressure is augmented by the dehydration of sedimentary minerals upon compaction. Clay minerals contain water of hydration in their crystal structures. As sediments are buried deeper and deeper, the weight of the overlying material expells water from both the pore spaces and the crystal lattice. This process, called diagenesis, results in an increasing rock density. The clayey sediments become shales, and the diagenetic waters which are freed up flow toward the most accessible porous rock unit.

The type-case for geopressurized geothermal resources is the thick wedge of Tertiary sediments on the continent and shelf along the northern Gulf of Mexico. The properties of this basin are generalized in Drawing C-7 after Wallace et al., 1979. The upper zone is a massive sandstone facies. It has higher than normal salinity and ordinary formation pressures. Underlying is a transition zone, of about two kilometers thickness, which is made up of alternating sandstones and shales. Salinity is moderate and formation pressures are in excess of hydrostatic.

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Drawing C-7 follows

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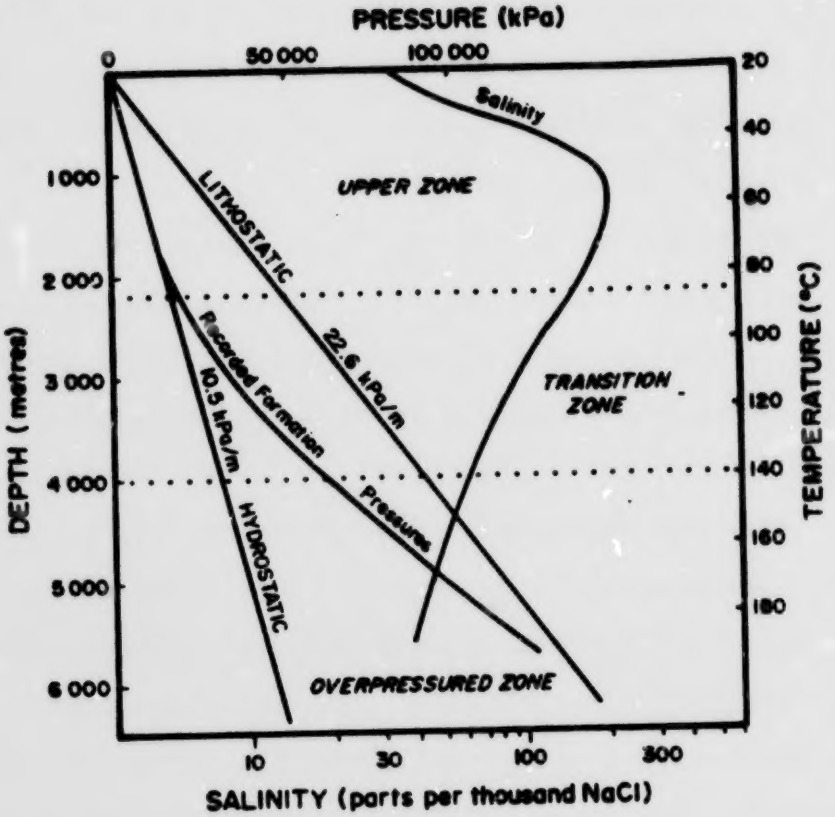

DRAWING C-7

GENERALIZED PROPERTIES
OF GEOPRESSURIZED
BRINES IN TEXAS GULF
(after Wallace et.al., 1979)

The lower or geopressurized zone generally lies beneath four kilometers. It contains more shale than sand. Pressures approach lithostatic, and salinity is low, locally dropping below seawater composition (about 30 parts per thousand) owing to dilution of the brine by water expelled from sediments.

There are three components to the energy contained in geopressurized reservoirs. First is the thermal energy contained in the brine owing to its depth-related high temperature. Second is dissolved methane in the brine. Under the pressure and temperature conditions in the reservoir, methane is soluble in the brine, and is easily extractable at a surface plant. The energy of combustion of the methane gas amounts to about 50% of the thermal energy in the brine. The third component of stored energy is mechanical, resulting from the formation pressure. The fluid would have the ability to perform mechanical work at or near the well head. The magnitude of stored mechanical energy, however, is relatively small in comparison to thermal and methane energy, amounting to about 1/250th of the thermal energy in the Gulf model.

Deep Circulation Systems. We have applied the term "Rocky Mountain geothermal systems" to the type of hot spring and subjacent thermal and ground water regime described in Appendix C.2. These are particularly abundant in British Columbia (see Section 3.0).

The sedimentary rocks controlling such systems are highly deformed--folded and faulted on a regional scale (see Drawings C-2 and C-6). Fluid flow is dominated by the interconnection of faults which have internal voids and steeply inclined permeable beds. Fracture surfaces, particularly for major faults, can be traced for many kilometers along the ground. Although seldom directly observed, void spaces within fractures commonly have thicknesses of a few centimeters, or in some instances as much as thirty or forty centimeters.

Deep circulation, however, is not limited to terranes of sedimentary rocks. It is likely that some of the hot springs in the Coast Crystalline Belt, for example, originate by means of deep circulation through interconnected fractures, brittle pendants or metamorphic rocks, and other permeable features of that predominantly granitic terrane.

Deep circulation systems tend to have vertical dimensions on the order of 2-4 km and horizontal dimensions of less than 10 km. This configuration is far different than the pancake shapes of aquifers in sedimentary basins.

The maximum temperature of a deep circulation system is foremost a function of the depth of circulation and discover such systems which have no natural outlet or hot spring at the present time.

C.5. Igneous-Related Systems

Many forward thinking individuals in geothermal research and development are attracted to the possibilities for extracting thermal energy from large and hot bodies of rock which are not naturally accessed by water, and which occur within drilling distance of the earth's surface. Los Alamos Scientific Laboratory (LASL), in New Mexico, an arm of the University of California, is a leader in such studies under the auspices of the U.S. Department of Energy. Their annual reports are widely distributed and should be consulted by the interested reader.

Hot Dry Rock. LASL is experimenting with a site in New Mexico. They have drilled several wells to depths of approximately 3000 m in a dry granite body which has a temperature of about 200°C at that depth. The test project has attempted to use standard oil field hydrofracturing techniques to shatter the rock and establish communication between the bottom parts of the wells. After mixed success early in the program, the latest report (LASL, 1980) is that an effective heat transfer area of at least 50 000 m^2 has been developed between two of the wells. Water circulating through the system reached a sustained temperature of 132°C at the surface during a 23-day flow test. The amount of fluid and the amount of heat extracted were not disclosed.

Hot dry rock reservoirs are known to exist in several places throughout the Western United States and elsewhere in the world. The LASL experiments are viewed with interest since they are making important contributions to aspects of geothermal reservoir stimulation, and, incidentally, to development of directional drilling equipment capable of withstanding high temperatures. However, widespread commercial utilization of hot dry rock appears to lie some decades in the future.

Heat from Molten Rock. Researchers in volcanic energy have examined craters containing molten lava from time to time, notably in one experiment at Kilaeau, Hawaii, about a decade ago. The extremely high temperatures of molten rocks--650 to 900°C--make this an attractive type of energy in theory. The practical realities at the present day are that no materials exist which can penetrate in such an environment and serve as heat exchangers. In addition, near-surface pipes or pools of lava tend to be unstable and unpredictable, during the few decades which would be needed to amortize a capital investment for an energy plant. Geologists have noted that from time to time lava plugs and ponds are withdrawn abruptly back into the ground; and at times are displaced upward as renewed eruptions begin.

C.6. Dissolved Solids and Gases

Nearly all natural surface and groundwaters contain some solids and gases. Geothermal waters generally contain more impurities than low-temperature waters.

Chemistry of geothermal fluids is extremely complex and its study is a distinct specialty within the geothermal industry. Chemistry of fluids is highly variable from place to place, and each reservoir has to be studied to determine its own pecularities. There are several ramifications of chemical constituents of a hydrothermal water or steam:

1. in exploration, estimates of reservoir temperature can be made from the chemistry of hot spring or test well waters;
2. fluid chemistry has to be considered in plant design so that equipment does not plug up with precipitates or corrode; so that condensers are not designed for a generating system with too much non-condensable gas;
3. health, safety and well-being of humans and their nearby activities (such as agriculture) are not jeopardized by release of unacceptable

levels of trace elements into the atmosphere or into surface waters.

Hydrothermal Systems. Table C-1 gives a repre-

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Table C-1 follows

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sentative range of solid trace elements in four high-temperature geothermal wells, ranging from the extremely clean fluid of Namafjall, Iceland (at about 600 ppm dissolved solids), to the brine in one Salton Sea well (which is nearly 10 times saltier than sea water).

Sodium and calcium are generally predominant cations with or without potassium and magnesium; anions are principally chloride, sulfate, carbonate (and bicarbonate). Many minor solid constituents are present in detectable quantities. These can include heavy and light metals, and halogen anions.

High temperature geothermal fluids generally contain dissolved silica gels in proportion to the temperature of their chemical equilibrium with the surrounding reservoir rocks. Note that in Table C-1 these values vary from about 320 to 480 parts per million.

Principal dissolved gases in hydrothermal systems are carbon dioxide, nitrogen, and minor amounts of helium, radon and hydrogen sulfide.

TABLE C-1 Dissolved Solids Content of Four Geothermal Wells, Selected to Demonstrate Range of Values (after Wahl, 1977, pp. 34-35)

	Namafjall 5, Iceland	Orakeikoraku 2, New Zealand	Ahuchapan, El Salvador	Salton Sea IID 1, U.S.
Temperature (°C)	212	260	228	
pH	7.5	9.1	7	5.2
values below in parts per million (ppm)				
Total dissolved solids	597	1781	15 024	258 000
chloride (Cl^-)	17.7	545	8 407	155 000
bicarbonate (HCO_3^-)	62.2	-	-	108
bisulfate (HSO_4^-)	37.7	142	-	-
sulfide ($S^=$)	-	-	-	21
fluoride (F^-)	0.9	5.7	-	-
borate ($H_2BO_3^-$)	-	-	22	69
sodium (Na^+)	102.7	550	4 839	50 400
calcium (Ca^{++})	1.3	-1	341	28 000
magnesium (Mg^{++})	0.02	-	-	54
lithium (Li^+)	-	3.1	-	215
potassium (K^+)	16.9	54	872	17 500
silica (SiO_2)	318	480	439	400
ferric iron (Fe^{+++})	-	-	-	2 090
other heavy metals	-	1	-	2 830

Notes: "-1" means "less than 1"; "other heavy metals" include rubidium, cesium, barium, manganese, zinc, lead and copper.

Sedimentary Systems. The principal dissolved solids in sedimentary brines tend to be calcite (calcium carbonate), gypsum (calcium sulfate) and salt (sodium chloride) in amounts up to a maximum of about 150 000 ppm. Low temperature fluids tend to contain less heavy metals than hydrothermal systems and fewer of the elements and compounds generally derived from or mobilized by magma, such as lithium, fluorine, mercury, radon and silica.

Gases include those found in oil and gas fields: methane, hydrogen sulfide, helium, carbon dioxide, etc.

In general, the fluids tend to be slightly alkaline and slightly reducing (oxygen deficient) in their nature.

Compositions are highly variable from field to field, but unlike hydrothermal systems, there are no significant relationships between temperature and composition.

APPENDIX D. EXPLORATION TECHNOLOGY

D. EXPLORATION TECHNOLOGY

D.1. History and Logic

Exploration is defined as all those technical and decision-making activities which are applied to a given area over a period of time and, whether successful or unsuccessful, are directed toward drilling and completing one well capable of producing geothermal fluid which has apparent commercial characteristics of temperature, pressure, and rate of flow. Exploration makes use of the geological and geophysical arts and drilling technology. Exploration often starts and stops over a period of months or years, as it proceeds in stages to acquire and evaluate new data. In Canada, these stages are generally timed on a seasonal basis.

Although we are defining exploration as the activity which precedes a discovery, commercial development does not proceed automatically following exploration. Drilling of confirmation wells, drilling of production well, testing, and feasibility and engineering studies are required before reaching a production stage. The technology used in exloration continues to be applied throughout the development stages which may follow a discovery.

The distinction between exploration and development should be clear. Exploration is the search; development is building the means of extraction. The early use of minerals by man did not involve exploration. Oil was first used from natural seeps in the Middle East, in Pennsylvania and elsewhere. The first coal burned came from natural outcrops. Similarly metals were first discovered in outcrop and their reduction and upgrading were the result of serendipitous contact with camp fires. Since the early use of minerals we have learned that there are many hidden deposits in the earth's crust, and the craft of exploration grew up as a means of finding concealed deposits.

The geothermal industry is analogous to the other extractive industries. The first developments of geothermal energy were placed on obvious resources. As earth sciences and technology progressed it became obvious that concealed deposits outnumber obvious deposits by many times. Since no super-boiling geothermal manifestations are known to exist in Canada, any development depends first upon the extent and success of exploration.

For purposes of discussion we will characterize exploration programs as either (1) large-scale and systematic, or (2) scale-scale, with limited objectives. The intended end-use of the geothermal resource has bearing on the type of exploration program which is justified. Reviewing the end-uses they are:

1. system electric use
2. local electric use
3. direct use for space heating
4. direct use for industry, agriculture and aquaculture.

With a few exceptions only the intended use for system electric generating justifies large-scale exploration. Large-scale geothermal exploration follows the same premises as any other mineral exploration venture, including oil and metals:

1. The mineral commodity sought has value.
2. Because the explorer has no control over where the mineral might occur, it must be transportable without loss of value; thus the explorer can range over a large geographic area and increase his probability of success by so-doing.
3. All of the explorer's expenditure is at risk since there exists an uncertainty of the success of any individual site-specific project.
4. The explorer is willing to take this risk, judging it as acceptable in light of the expected value of the commodity and his perception of his probability of success.
5. The explorer has reason for believing in his long-term success because of a body of experience

which suggests that many attempts enhance the probabilities of success, and that he has sufficient risk capital and determination to make those many attempts, and lastly, because he has a faith in his own skills.

Small-scale exploration, generally a site-specific program, is unlike most other current mineral exploration practices. Its logic is rigid: A daring individual or group desire to meet a local need and accept being put at risk to drill for a commodity which may not be discovered, and if discovered, may have limits placed on its value by its non-portable nature.

The following section presents the technology used in large-scale exploration; following that a model small-scale exploration program is derived.

D.2. Large-Scale Exploration

Systematic exploration is a sequential activity which generally starts with reconnaissance of a large geographic area, for example 100 000 square kilometers, and culminates with the drilling of a well for a discovery. The objective of the reconnaissance stage is to select one or more prospect areas, which might be as small as 4 square kilometers or as large as 200 square kilometers. Prospects are then ranked according to their characteristics, and detailed exploration proceeds on one or more prospects. The objective of work on a prospect is to establish the most promising point for drilling the first well aimed at discovery. The entire sequence of exploration and development is shown graphically in Drawing D-1.

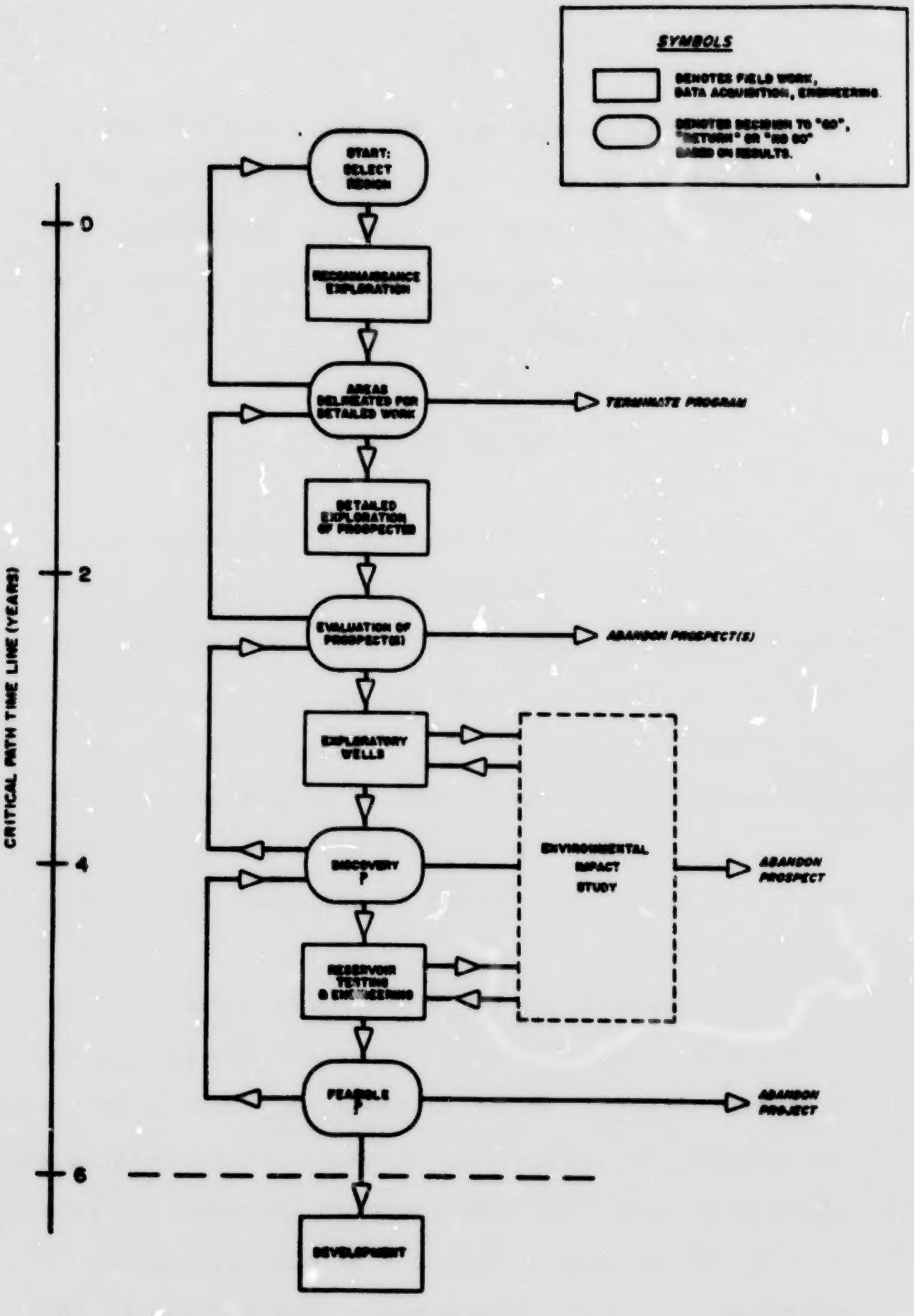
- - - - - - - - - - -

Drawing D-1 follows

- - - - - - - - - - -

The reason for the sequence of activity is that deep drilling for a discovery is an expensive undertaking. The success of the effort, per exploration dollar committed, is optimized by using less expensive techniques to select the drill site. The less expensive techniques used comprise an analysis of the direct and indirect geological and physical properties which are known or inferred to accompany large hydrothermal systems.

With relation to the hydrothermal systems, some of the direct and indirect properties are causes, and some are effects. Which of these they are is of little importance, so long as the observation and measurement of these properties can contribute an increment of information to the program. Each set of observations or measurements constitutes a test. The outcome of this test might be a decision to abandon a prospect at an


SYMBOLS
DENOTES FIELD WORK, DATA ACQUISITION, ENGINEERING.
DENOTES DECISION TO "GO", "RETURN" OR "NO GO" BASED ON RESULTS.
CRITICAL PATH TIME LINE (YEARS)
0
2
4
6
START: SELECT REGION
RECONNAISSANCE EXPLORATION
AREAS DELINEATED FOR DETAILED WORK
TERMINATE PROGRAM
DETAILED EXPLORATION OF PROSPECTS
EVALUATION OF PROSPECT(S)
ABANDON PROSPECT(S)
EXPLORATORY WELLS
DISCOVERY ?
ENVIRONMENTAL IMPACT STUDY
ABANDON PROSPECT
RESERVOIR TESTING & ENGINEERING
FEASIBLE ?
ABANDON PROJECT
DEVELOPMENT

DRAWING D-1

TYPICAL EXPLORATION PROGRAM FOR LARGE SYSTEM ELECTRIC GEOTHERMAL RESERVOIR early stage (see Drawing D-1), or it might be to accelerate the project with the promise of increased probability of success. Some of the tests are designed to serve as vectors, to point in a favourable direction within a given prospect, or to provide guidance in the design of further exploration tests.

In a systematic program the generally accepted philosophy is that for a large number of prospects examined in detail, most will be abandoned and only a few will be drilled. Expectations for every drill hole aimed at discovery are such that only a few will be successful. A complete flow sheet for a systematic exploration program would be shaped like an inverted pyramid, with dozens of specific areas rejected along the path to one successful discovery.

Specific exploration techniques which have been used in geothermal exploration, with special reference to conditions of geology and groundwater which exist in British Columbia, are given below.

D.2.1. Reconnaissance

Airborne infrared scanning. This method comes to mind readily and was widely touted until about five years ago. In theory IR scanning picks out hot spots and is rapid and relatively inexpensive.

Its application to geothermal resource exploration is restricted by the overwhelming influence that other factors have on the temperature of the earth's surface. Such factors are solar radiation, ambient air temperature, and the differing textures, reflective characteristics, and thermal properties of vegetation, rocks and soils. It is impossible to adequately interpret IR data over the large areas, the hundreds of thousands of square kilometers, surveyed in geothermal reconnaissance.

Most hydrothermal systems do not produce a large area of increased surface temperature. In particular such effects are precluded in British Columbia by a regime of cold groundwater. Low level, high resolution IR has been used in British Columbia to identify and locate hot springs, but this is only useful in selected small areas. The technique has been abandoned by most workers in the field.

Geochemistry. The trace elements in hot springs waters often provide some clues as to the type of system from which the waters originate. One of the focal points for reconnaissance is examination of thermal springs, notwithstanding the often spurious relationships between hydrothermal resources and hot springs (as discussed in Appendix C).

The most abundant dissolved solids in thermal springs are silica, sodium, potassium, calcium, magnesium, chloride, sulfate, and bicarbonate. The concentration of some of these ions is partially a function of temperature-dependent equilibria between the hot geothermal water and the common rock forming minerals. Complex formulae have been worked out as estimators for the temperature of the underlying geothermal reservoir based on the content of silica, the ratio between sodium, potassium and calcium concentrations, and the concentration of dissolved chlorine.

The ratios among the various isotopes of carbon, oxygen and hydrogen and the amounts and proportion of dissolved gases are similarly used to provide information on the reservoir, and sometimes to lead to a temperature estimate.

Appendix C and Section 3.0 noted that hot springs in British Columbia are products of geothermal waters which have been highly diluted by ordinary groundwaters. We have found, for example, that the temperature-estimating chemical constituents of the hot springs deriving from the Meager Creek geothermal system have been reset at the relatively low temperature of 80°C (Hammerstrom and Brown, 1977). This re-setting to a lower temperature is a combined effect deriving from mixing of the geothermal waters with cool groundwater, a relatively slow ascent from the geothermal reservoir to the surface, and chemical reactions at lower temperatures between the hot water and the wall rocks.

The acquisition and interpretation of chemical data from thermal waters is a highly developed specialty. Its use in reconnaissance exploration is valuable, but it is not definitive in British Columbia (nor generally in Washington, Yukon, or Southeast Alaska). Geochemistry is always practised in reconnaissance exploration stages. As the body of chemical information builds with reference to a specific geothermal prospect, such information becomes increasingly valuable. The application of geochemistry continues past the reconnaissance stage into the detailed prospect examination stage, when the waters sampled are usually from shallow wells, and on into the deep exploratory stages. The early objectives of geochemical work are to estimate reservoir temperature and deduce other reservoir characteristics. As work draws to the point of discovery or continues beyond, geochemistry is used to complete the understanding of the geothermal system and to begin planning for the engineering measures necessary, to protect the environment and to design the plant, to handle dissolved solid and gaseous impurities.

Electrical Methods. "Self-potential" is one of the earliest prospecting methods used for metals. It consists simply of measuring the difference in voltage (potential) between two electrodes placed in the ground at a measured and pre-determined distance apart, and continuing a traverse of several such measurements. It is a passive method, vis. it measures a natural phenomenon, without introducing a current or otherwise disturbing that phenomenon.

Observation and theory indicate that where a column of geothermal fluid ascends from a reservoir a partioning of cations and anions takes place which results in a distinct distribution of electric charges at the surface of the ground. When mapped, the distribution of these charges has a shape ideally like that of a Mexican hat: a positive voltage in the center surrounded by an annular negative zone. The method is sometimes definitive in recognizing the prime location to begin more detailed work on an inferred geothermal system. For example, the North Reservoir at Meager Creek displays one of the largest self potential anomalies recorded in world geologic literature (Shore, 1980). In other instances, the results may be ambiguous or garbled, due to the influence of many other factors (Crandall and Sadlier-Brown, 1976).

Airborne Magnetic Surveys. In many areas of British Columbia the Federal Government has conducted regional airborne magnetic surveys as an adjunct to metal exploration activities and to the studies of regional physical geology. Such maps are available to the public through the offices of the Geological Survey of Canada and other data sources. Most are at scales of 1:50 000 or 1:250 000.

The causes and sources of variations in the magnetic field over the earth's surface are beyond the scope of this report. Nevertheless, airborne magnetic maps are useful in a preliminary assessment of the structural "grain" of a region, the boundaries between dissimilar geologic terrains, and the distribution of either highly magnetic or non-magnetic rock units. Generally, no definitive interpretations result from the study of aeromag maps in the application for geothermal exploration. Some authorities have produced evidence that large hydrothermal reservoirs are magnetically dead; on the other hand, large accumulations of volcanic rocks, which may overlie a hydrothermal system, are noted for having high and highly erratic magnetic properties. The workmanlike exploration technician always examines aeromagnetic maps, if they are available, before embarking on a regional program.

Geological Mapping and Airphoto Interpretation. The most important technique for initial exploration is geological observation and mapping. Features of importance which are noted during reconnaissance geologic mapping are:

1. rock types and the sizes, shapes and orientations of rock bodies in space
2. the relative ages of the rocks
3. faults, fractures, their orientations, densities, and senses of movement
4. any chemical or mineralogic changes imposed on the rocks subsequent to their formation.

In particular, the explorer seeks evidence of past flooding of the rock with hydrothermal solutions. Such evidence includes alteration of rocks to assemblages of clays, micas, silica veins, iron sulfides and oxides, or carbonates.

Reconnaissance geologic mapping is generally conducted at scales of 1:50 000 to 1:250 000. In the course of any reconnaissance mapping program aerial photographs are utilized to their fullest extent. They are generally examined through a stereoscope, giving a three-dimensional image. The nature and continuity of rocks and faults can be determined and plotted on the map from the air photos, subject to periodic control by examination of the features on the ground.

Aerial photographs covering much of British Columbia are available from the Ministry of Energy, Mines and Petroleum Resources, Air Photo Library, Victoria. The most common scales are 1:15 840 and 1:31 680, and nearly all photos are black and white. In later stages of work the explorer often contracts for his own aerial photos over a selected area, generally in colour and in false-colour infrared, and at a larger scale.

In recent years satellite images have become useful tools for the geologist concerned with regional exploration. Two classes of satellite images are readily available: LANDSAT (formerly ERTS) and SKYLAB. The former are electronic images transmitted to earth and reproduced on magnetic tape or on photographic images constructed of tones lines, much the same as television images. They are in a variety of visible and near-infrared wave-bands. Their resolution is such that nothing smaller than a football field can be readily identified. SKYLAB images are photographs returned physically to earth, and generally reproduced as high quality black and white photographs representing a number of light wave-bands.

Satellite images are available from the Canada Center for Remote Sensing, Ottawa, or the NASA distribution center in Sioux Falls, South Dakota. They are used in the same fashion as air photographs. Contrary to widely held opinion, there is no widespread thermal infrared coverage available to civilians from satellite sensors. Moreover, if such data were available, it is questionable as to whether or not resolution and contrast would be applicable to geothermal resource exploration.

D.2.2. Detailed Prospect Evaluation

Each geothermal prospect has its own unique character and the detailed exploration of an area, once selected, must be designed and executed with the local variables in mind. Certain tasks are continued forward from the reconnaissance stage in more detail. Several techniques which are used in desert or tropical areas are not useful in British Columbia, or are useful only if modified. Similarly certain techniques which are shunned elsewhere are highly useful in the geologic and hydrologic regimes of British Columbia.

Drawing D-2 is a series of cross-sections

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Drawing D-2 follows

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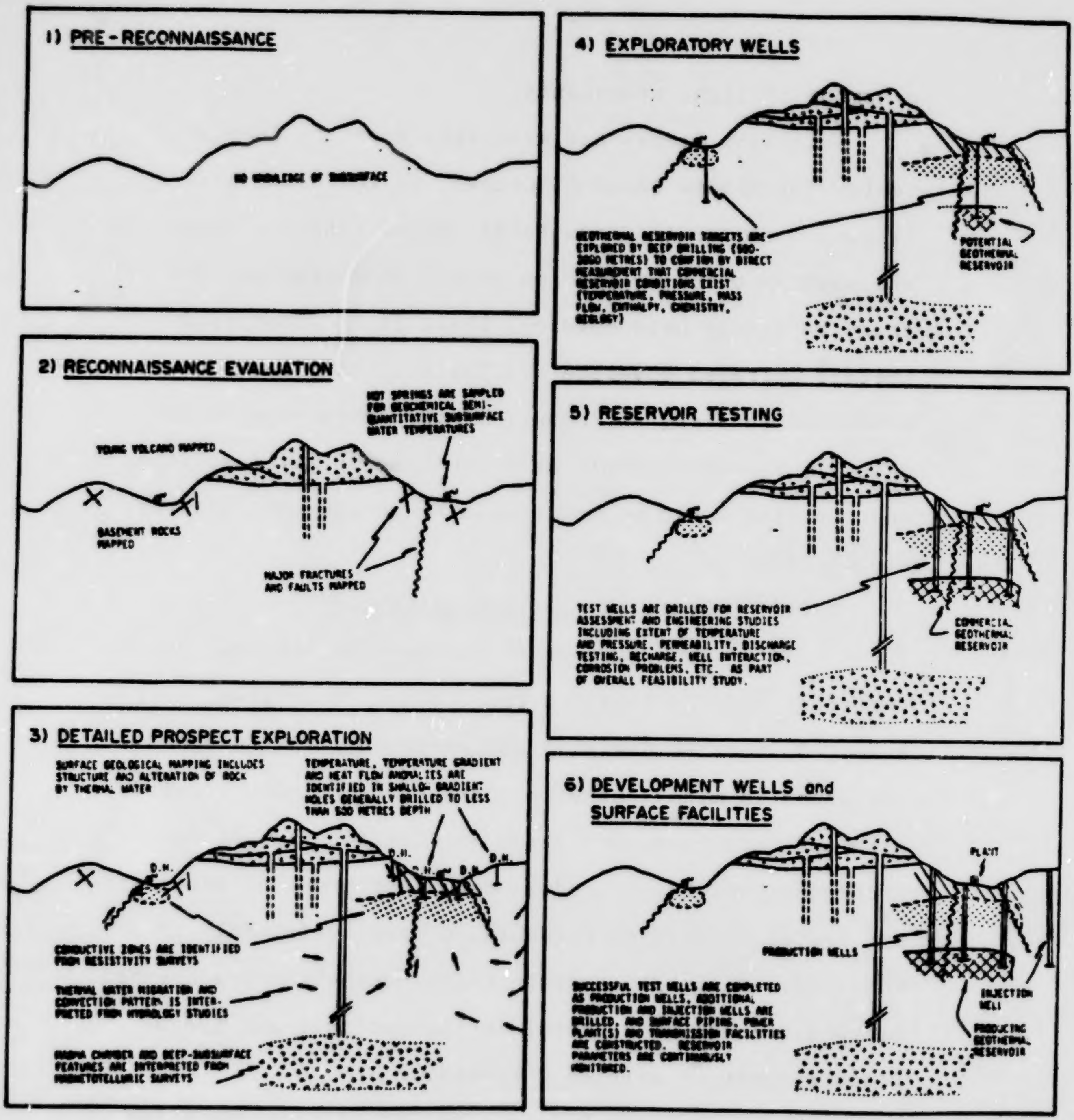
1) PRE-RECONNAISSANCE
NO KNOWLEDGE OF SUBSURFACE
2) RECONNAISSANCE EVALUATION
HOT SPRINGS ARE SAMPLED FOR GEOCHEMICAL SEMI-QUANTITATIVE SUBSURFACE WATER TEMPERATURES
YOUNG VOLCANO MAPPED
BASEMENT ROCKS MAPPED
MAJOR FRACTURES AND FAULTS MAPPED
3) DETAILED PROSPECT EXPLORATION
SURFACE GEOLOGICAL MAPPING INCLUDES STRUCTURE AND ALTERATION OF ROCK BY THERMAL WATER
TEMPERATURE, TEMPERATURE GRADIENT AND HEAT FLOW ANOMALIES ARE IDENTIFIED IN SHALLOW GRADIENT HOLES GENERALLY DRILLED TO LESS THAN 500 METRES DEPTH
D.H.
D.H.
D.H.
D.H.
D.H.
CONDUCTIVE ZONES ARE IDENTIFIED FROM RESISTIVITY SURVEYS
THERMAL WATER MIGRATION AND CONVECTION PATTERN IS INTERPRETED FROM HYDROLOGY STUDIES
MAGMA CHAMBER AND DEEP-SUBSURFACE FEATURES ARE INTERPRETED FROM MAGNETOTELLURIC SURVEYS
4) EXPLORATORY WELLS
GEOTHERMAL RESERVOIR TARGETS ARE EXPLORED BY DEEP DRILLING (500-3000 METRES) TO CONFIRM BY DIRECT MEASUREMENT THAT COMMERCIAL RESERVOIR CONDITIONS EXIST (TEMPERATURE, PRESSURE, MASS FLOW, ENTHALPY, CHEMISTRY, GEOLOGY)
POTENTIAL GEOTHERMAL RESERVOIR
5) RESERVOIR TESTING
TEST WELLS ARE DRILLED FOR RESERVOIR ASSESSMENT AND ENGINEERING STUDIES INCLUDING EXTENT OF TEMPERATURE AND PRESSURE, PERMEABILITY, DISCHARGE TESTING, RECHARGE, WELL INTERACTION, CORROSION PROBLEMS, ETC. AS PART OF OVERALL FEASIBILITY STUDY.
COMMERCIAL GEOTHERMAL RESERVOIR
6) DEVELOPMENT WELLS and SURFACE FACILITIES
PLANT
PRODUCTION WELLS
SUCCESSFUL TEST WELLS ARE COMPLETED AS PRODUCTION WELLS. ADDITIONAL PRODUCTION AND INJECTION WELLS ARE DRILLED, AND SURFACE PIPING, POWER PLANT(S) AND TRANSMISSION FACILITIES ARE CONSTRUCTED. RESERVOIR PARAMETERS ARE CONTINUOUSLY MONITORED.
INJECTION WELL
PRODUCING GEOTHERMAL RESERVOIR

DRAWING D-2

SCHEMATIC DRAWINGS ILLUSTRATING HOW EXPLORATION PROCEEDS THROUGH SUCCESSIVE STAGES, AND HOW KNOWLEDGE OF THE SUBSURFACE IS BUILT UP.

illustrating how the various steps on a geothermal prospect are applied in sequence to lead up to discovery and development. It is patterned after a typical Cascade or Garibaldi volcano program.

Geologic Mapping. Geologic mapping continues into the detailed exploration stage, and is generally upgraded to a scale on the order of 1:10 000. Geologic cross-sections are generated from map data for the first time. Several alternative working hypotheses for the geologic features in the subsurface are derived and serve as models for guiding additional work. Geologic data are continually refined and integrated with drill hole data. Maps and cross-sections of areas of special interest are constructed at scales of 1:1 000.

Electrical Methods. Electrical resistivity is an active exploration method and consists of placing four electrodes in the ground, according to a specifically designed array. An electrical current is generated and passed through the ground between two to the electrodes, and the response from that current is measured between the other two electrodes. The entire array is moved from place to place, according to a design pattern throughout the prospect area.

The property which is measured by this survey is the electrical resistance of a large volume of earth, or its specific analog "resistivity", measured in ohm-meters. A three-dimensional pattern is developed from these data, much as if the upper part of the earth's crust consisted of building blocks of unequal electrical properties. Representations of the data are made by means of maps, vertical profiles, and cross-section approximations called "pseudosections".

Electrical resistivity surveys make use of the observed and theoretical phenomenon that rocks saturated with hot geothermal waters are far more conductive than rocks saturated with ordinary groundwater. That is, the electrical resistivity of a geothermal reservoir and its outflow plume is lower than the resistivity of its surroundings. The reasons for the low resistivity are that (1) hydrothermal waters contain total dissolved solids (TDS) of 2 000 parts per million or more, whereas ordinary groundwaters might contain 20 parts per million TDS; (2) that geothermal reservoirs often occupy zones of inherently high porosity; and that (3) hydrothermal waters often chemically alter the surrounding wall rocks to more conductive minerals.

Electric resistivity surveys in British Columbia have produced figures of high contrast: for example, 20 to 30 ohm-meters as a value for a known geothermal reservoir versus 2 000 ohm-meters as a value for adjacent non-reservoir rocks. We regard resistivity as a valuable technique.

It is considered less valuable in semi-arid parts of the United States or in volcanic terrains in some equatorial countries, because the ordinary geologic regime contains a large fraction of conductive salts and contrast is insufficient to allow resistivity a definitive role.

Resistivity surveys are generally conducted along lines cut by hand through the bush. Stations are placed at intervals of 500 or 1 000 meters. The crew generally consists of about six people and is lead by a geophysicist. Data was reduced to usable form immediately in the field by means of a portable computer. Electrical resistivity has a high resolution to a depth of about 500 meters; below that, data are recovered, but, like a blurry photograph, often have uncertain meaning.

This technique was borrowed from one widely used in metal exploration and groundwater surveys and adapted to geothermal work. Equipment and operators are readily available in British Columbia.

There are many variants of electrical methods, including magnetotellurics and electro-magnetics. These have a proper application and have been used in geothermal studies. The above discussion of simple resistivity should suffice to illustrate the methods.

Seismicity. Large hydrothermal systems tend to occur in tectonically active areas. The process of faulting and deformation of the earth's crust which went hand in hand with the emplacement of the original magma continues throughout much of the life of the hydrothermal cell. Some geothermal zones are in high earthquake regions (e.g. Central Nevada; Yellowstone Park, Western California). Others tend to have fewer large earthquakes, but are generating microearthquakes continuously. The focal points of microearthquakes, generally less than Richter magnitude "minus three,"* often coincide with the most actively circulating parts of the hydrothermal reservoir. A mutual cause and effect relationship is in force: microfaulting keeps the void spaces open where the geothermal fluids circulate, and the geothermal fluids lubricate fractures and facilitate continued microfaulting.

Microearthquake surveys are conducted with an array of as many as six widely spaced and sensitive seismographs, all of which record on the same magnetic tape at a central station. Such seismographs may be placed on the surface or in shallow drill holes. Data recorded during a period of a few months allow pin-pointing of the highest microearthquake zones in three dimensions.

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*The Richter scale is exponential. An earthquake of magnitude "6" is one-tenth as powerful as one of magnitude "7". A microearthquake of magnitude "-3" is 1/10 000th as powerful as a magnitude "1" earthquake.

Except for a preliminary one-station survey at Meager Creek, which had negative or equivocal results (NSBG, 1975a), no work of this nature has been done in British Columbia. The technique is highly regarded by some in the United States. There is no equipment available in Canada for a comprehensive microearthquake survey. At least three contractors in the U.S. offer these services.

There are many other active or passive sonic methods. Refraction seismic surveys are an active method which records the shock wave velocity from a dynamite charge. Refraction is widely used to determine the depth and character of overburden prior to drilling.

A method for deep crustal study is S-wave attenuation. This is used to test for the existence of a liquid or plastic magma chamber at a depth of 10 kilometers or more beneath a prospective geothermal area. While it contributes to the science surrounding the origin of geothermal reservoirs, it is of little practical value in exploration.

Shallow Drill Holes. All of the preceding steps leading up to shallow drilling have accumulated information which is primarily lateral in its distribution. Shallow wells are the first increments of hard information along vertical coordinates--downward toward the prospective hydrothermal reservoir. The data measured and calculated from shallow wells includes the distribution of temperatures, temperature gradients, and flow of heat in three dimensional space.

The outstanding and obvious direct property of hydrothermal reservoirs is their high temperature. Where a body exists at a temperature of, say, 300°C within three kilometers of the earth's surface, it will give off heat upward and laterally and produce a dual set of clues to its existence: a high temperature gradient and a high heat flow. Each of these measurements is interrelated with the other; however, they are two distinct parameters.

The distinction is this: temperature gradient is the amount of increase of temperature with depth. Heat flow is a calculated value, the product of the temperature gradient and a measured property of the rock, the thermal conductivity.

It is a common observation that measured heat flow values over commercial geothermal reservoirs may be 5 to 10 times the value of heat flow in ordinary areas.

Both parameters are useful; both are the first direct thermal data in a systematic exploration program. And both require care and skill in interpretation.

The sites for shallow wells are picked on the basis of geological information and the synthesis of information from preceding stages. Wells are generally spaces at regular or irregular intervals of 500 to 1 000 meters. More than a dozen shallow wells, or as many as 50 or 60, are generally drilled before starting a deep well oriented toward discovery.

In desert areas of the United States, a preliminary temperature gradient drill hole may acquire valuable information at a depth of 100 to 200 meters--information which might be projected to a depth of 1 000 meters. Annual precipitation in prospective areas in British Columbia ranges from 40 cm to more than 300 cm. Some of this falls as snow and some adds to permanent snow caps or ice caps, which in turn feed the surface and groundwater supply during hot, dry seasons. The near-surface rock and soil materials are highly saturated with groundwater and are subject to continuous recharge, flow through, and discharge of cold groundwater. Experience in British Columbia, particularly at the Meager Creek geothermal area, indicates that reliable temperature information does not begin to accrue until depths of 200, 300, or even 500 meters are reached.

Since near-surface temperature information is distorted by the cold groundwater flux, the design, drilling and interpretation of data from shallow drilling requires a sensitivity to groundwater hydrology, as well as to hard-rock geology.

In the United States truck-mounted rotary drills, generally using air as the drilling medium, are employed most frequently in shallow temperature-gradient drilling. These drills are readily available, highly mobile, and rapid in progress, all of which result in low unit costs. In Canada skid-mounted or truck-mounted diamond drills are used for this purpose. Skid-mounted diamond drills are readily available and helicopter-portable. Drilling progresses more slowly through soft or unconsolidated materials with diamond drills; however, diamond drills make up for this disadvantage by a stronger capability to handle hard crystalline rock. Diamond drills recover an undisturbed core, contributing to the information available to the geologist for interpretation. They also have the advantage that bottom hole temperatures can be taken through the drill string, without the time or expense of "tripping" the drill string from the hole.

D.2.3. Drilling for Discovery

At the time of this writing B.C. Hydro is drilling the first well in Canada aimed at a hydrothermal resource discovery. The well has not reached total depth and results are not yet known.

There is a large body of knowledge on exploratory and production geothermal drilling. The Petroleum Information Corporation, a privately operated data bank, lists approximately 900 geothermal wells drilled and completed or drilled and abandoned in the United States through June, 1979. Although these span a period of more than fifty years, most were drilled during the 1970's (PIC, 1979). There is an even larger body of knowledge from drilling for petroleum, from which the geothermal drilling techniques are derived.

There is universal acceptance of the rotary drill as the principal exploration and production tool. Invariably, outside the socialist countries, the drills are owned and operated by contractors. For purposes of future work in British Columbia, rigs and crews are available in Canada and the United States, and at least one Canadian contractor, Westburne Industries Ltd., has drilled steam wells abroad in the Philippines. At least four Canadian resource companies have experience as owners of geothermal wells in the United States.

Several elements of design and operating concern, as well as cost control elements, are listed in Table D-1.

- - - - - - - - -

Table D-1 follows

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TABLE D-1 Design, Operating and Cost-Control Elements for Geothermal Well

Access road construction and maintenance

Site - location, layout, construction

Camp - design, construction, operation

Mobilization and demob

Rig up and down

Drilling and rig time

Water supply

Waste disposal during drilling

Depth program

Pipe and collars

Bits - types, quantity, size, life

Mud program - design, weight material, maintenance, cooling

Fuel and lubricants

Surface equipment--including Blow-out Preventor (BOP), wellhead, spares and specialized tools

Casing and cementing program - sizes, lengths, type, including centralizers

Logging - selection of logs, logging runs

Contingency for mishaps

Miscellaneous transportation

Supervision, administration, overhead, communications, public relations

Flow testing equipment, mufflers, liquid waste disposal pits.

Certain of the items are major and sensitive. Design depth is the most sensitive engineering consideration. Depth influences the selection of other variables; it influences the cost of the well (Appendix E) and it can be of significance in the success or failure of the program. The hardness of the rock influences the selection of bit type and the bit life. Bit life, or meters drilled before the bit wears out or fails, affects the time "tripping" (pulling the pipe out of the hole for a bit change and re-entering the hole).

Bit life is adversely affected by the high temperatures experienced in geothermal drilling. Considerable research and development are underway at present to develop temperature-resistant bearings, seals and alloys for geothermal drilling bits.

Presently available drilling muds do not withstand prolonged exposure to temperatures in excess of 150-200°C without deterioration which affects their performance. The purpose of muds is to contain pressure by high density, to float cuttings out of the well and drop them in the settling tanks, to cool the bit and bearings, to lubricate the rotating drill pipe against the casing or walls of the hole, and to penetrade and plug fractures in the formation so as to control loss of circulation. Cooling towers are required to preserve mud properties, and to reduce the risk of flash blow-outs of boiling mud.

Blow-out preventors (BOP's) are generally used on geothermal wells. Wellhead pressures are less than those experienced in deep drilling for gas; however, pressures can exceed the confining pressure of mud column. The initial O'Brien well (72-16) on the Roosevelt Geothermal Field, Utah, intersected a fracture producing high pressure super-boiling water at the relatively shallow depth of 400 meters, and required snubbing gear in order to complete the well. Most governmental jurisdictions require BOP's on geothermal wells; and most operators require BOP's for crew and equipment safety.

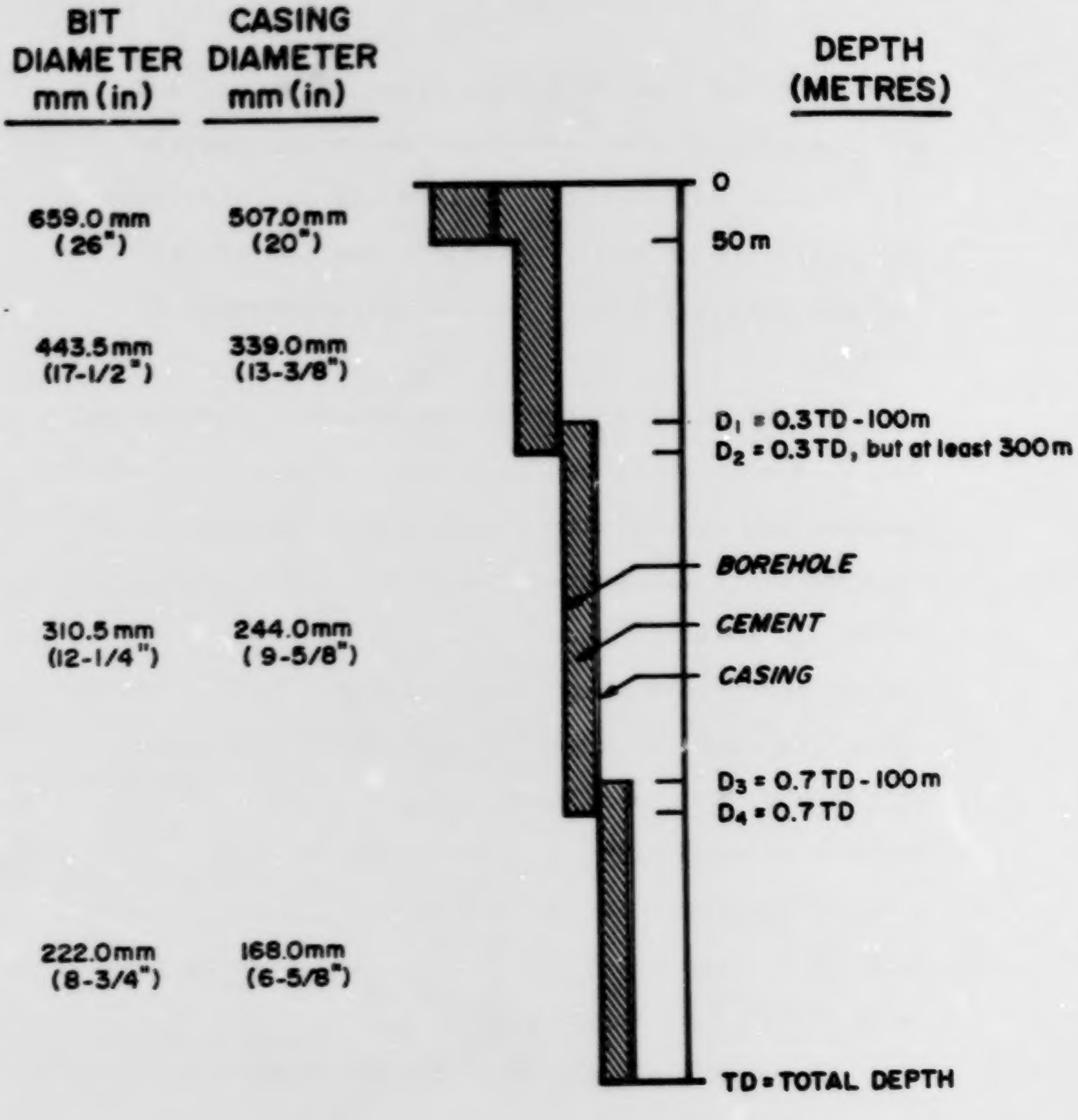
Drawing D-3 shows a representative casing and

- - - - - - - - - - -

Drawing D-3 follows

- - - - - - - - - - -

cementing program for an intermediate depth geothermal well, adapted from Entingh and Lopez (1979). There are many designs and varieties of casing and cementing programs. The full casing program is designed presuming a success. If the well is successful and the program is followed through, the process is called "completion." Success is not generally determined until the well


BIT DIAMETER mm (in)
CASING DIAMETER mm (in)
DEPTH (METRES)
659.0 mm (26")
507.0 mm (20")
443.5 mm (17-1/2")
339.0 mm (13-3/8")
310.5 mm (12-1/4")
244.0 mm (9-5/8")
222.0 mm (8-3/4")
168.0 mm (6-5/8")
0
50 m
D₁ = 0.3 TD - 100 m
D₂ = 0.3 TD, but at least 300 m
BOREHOLE
CEMENT
CASING
D₃ = 0.7 TD - 100 m
D₄ = 0.7 TD
TD = TOTAL DEPTH

DRAWING D-3

GENERAL DESIGN FOR
GEOTHERMAL WELL CASED-TO-BOTTOM,
INTERMEDIATE DEPTH
OF 1000 - 3000 m

(From Entingh & Lopez, 1979)

reaches or approaches target depth, however, and early stages of the casing and cementing program are carried out as the well is drilled. Unsuccessful wells are generally plugged, sealing off all of the aquifers which have become interconnected by drilling.

An important factor in completion of geothermal wells is to prevent casing failure from thermal expansion and contraction during the subsequent series of flow tests and shut-in periods. Casing has to be made from suitable steels and cements have to set to design strength at high temperatures. Casing centralizers are used in order to establish a continuous cement wall in the annulus between casing and open hole. The art of completing geothermal wells is a highly developed specialty in its own right. It has borrowed technology from heavy oil fields, those where production is stimulated by steam injection.

If successful, the drilling and completion of a discovery well leads naturally to the drilling and completion of production wells. The technology is identical. The only differences between exploratory and production drilling derive from the venture into the unknown which constitutes exploration. As knowledge of the rocks and the hydrothermal resource are developed in a given prospect, the drilling becomes somewhat more predictable in all of its parameters: rate of progress, equipment performance, etc. Nonetheless, geothermal drilling on a known field never reaches the same level of predictability as does oil and gas drilling on a known field. Relatively speaking, oil and gas occur in consistent sedimentary formations. Hydrothermal resources are in areas of complex igneous geology, in rocks shot through with steeply dipping fracture zones and unpredictable zones of hard and soft alteration minerals.

The unpredictability of geothermal drilling even under the best of circumstances leads to the contingency for drilling mishaps which enters into every design or cost estimate. There are many types of mishaps. One of the more common is to twist off the drill string. If this happens the contractor uses specialized gear to "fish" for the lost pipe and tools. Fishing itself is tedious and time-consuming, and at some predetermined point an unsuccessful fishing attempt is abandoned, and the well is re-drilled, either deflected past the lost tools, or at another site.

D.3. Small-Scale Exploration Projects

Small-scale exploration is a program where the end use is site-specific and the proposed energy production rate is limited in scope, at least initially. Generally this applies to local electric projects and to all direct use projects, unless the initial conception is massive.*

Exploration must be conducted on a limited area, i.e. the prospect is chosen involuntarily. Other things being equal, the probability of success is statistically reduced from the systematic program previously described, which choses the best from a large number of selected prospects.

D.3.1. Local Electric Use

Exploration for geothermal resources for local electric use faces an economic conundrum which is discussed in Appendix E.3.

For success, the program must discover a small quantity of a very high-temperature resource.

Technology differs from system electric exploration only in that, by economic necessity, fewer steps can be taken. A model program would be limited to geologic mapping, geochemistry of thermal waters, resistivity, 3 to 4 shallow temperature-gradient wells, and 1 or 2 small diameter rotary wells (e.g. 6¼" or 159 mm).

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*Various government agencies, underwritten by the Department of Energy, are studying the possibilities of a massive space heating project for Portland, Oregon, to be supplied from Mt. Hood, a Cascade volcano located some 70 kilometers to the east.

D.3.2. Direct-Use Projects

The history of exploration technology in past direct-use geothermal projects has been minimal. An imaginative entrepreneur simply drilled at or near an obvious hot spring or geyser system. The operator often lacked any formal knowledge of geology or hydrology, and any discoveries or production of hot water were on a hit-or-miss basis. Most direct-use operators have been involved in a previously established business and have tended to view geothermal heat as a savings in costs, rather than an undertaking with direct profit-making potential.

In communities such as Klamath Falls, Oregon, or Steamboat Springs, Nevada, local drilling and heating contractors became expert in the practical engineering needed for utilization.

The U.S. Department of Energy (DOE) has fostered a technology-intensive style of direct-use exploration and development during the past few years. Certain programs are large-scale, systematic and rigourous, and are much like the programs aimed at system electric end uses.

Exploration technology and rationale for direct-use applications differs from that for electric applications in three respects:

1. Target temperatures are generally lower. Whereas 230°C might be a minimum acceptable reservoir temperature for an electric project, 45-150°C might be acceptable for a given direct-use project. Since low temperature fluids are far more common, and often at shallower depths than high temperature fluids, the probabilities for success are greater.

2. There is less temperature-related wear and tear on drilling equipment. Wells can be drilled with conventional equipment and the only modification needed is an arrangement of flow lines or discharge lines so that the safety of the drillers is ensured. Cable tool drills (churn drills) are often used to drill geothermal wells to about 150-200 meters total depth. Liners are set as for ordinary water wells. Below 150-200 meters the capability of cable tool equipment is exceeded and rotary drills are used.

3. When a discovery is made the resource can be put to use immediately with fewer complications and no expense of conversion. The exploration and drilling cost is the major component of the pre-production capital cost.

APPENDIX E. EXPLORATION AND DRILLING COSTS

E. EXPLORATION AND DRILLING COSTS

E.1. Introduction

A wide range of exploration techniques and attitudes is reviewed in Appendix D. The cost of any mix of exploration techniques forms an element of production costs, but stands independent of other production costs; therefore all exploration costs are discussed in this section. Following the discussion of a wide range of exploration costs, several arbitrary but reasonable cost models are fixed in order to assess different production cost models.

The cost of both exploratory and production drilling is discussed in this appendix, and not in the economic models of Sections 4.0, 5.0, and 6.0.

As to non-electric thermal applications, all of the cost elements pertaining to exploration, discovery and supply of the resource are presented in this section.

E.2. System Electric Exploration

E.2.1. Components of Cost*

Appendix D describes a wide array of geological, geophysical, drilling, and other techniques used in a large-scale systematic exploration program. These elements are integrated into representative programs in this discussion without specific reference, for example, to the cost for geochemical surveys.

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*The basis used is the mid-1980 Canadian dollar. Some costs have risen in the period since the first draft of this report.

very little from the cost of diamond drilling done for the purpose of metal exploration throughout British Columbia.

The cost of shallow drilling, when added to the cost of surface work, brings the total for detailed examination of a prospect to the range of $500 000 to $1 000 000.

There is no provision specifically made in the cost of detailed work on a prospect for lease payments or otherwise obtaining rights to geothermal resources.

The single most sensitive cost of systematic exploration is the cost of deep drilling for a discovery. As previously mentioned deep exploratory wells differ from production wells only in that they are a venture into the unknown, and hence have a slightly higher cost. The variables in drilling, however, are so numerous that the unknown exploratory factor cannot be reliably quantified in a general equation.

An analysis of the cost of a broad sample of geothermal wells, both exploratory and production, was done recently by Chappell et al, (1979). Nineteen geothermal wells were statistically examined and an empirical exponential relationship was generated between depth and cost. We have transformed this regression from 1978 to 1980 dollars, and into Canadian currency (the factor used is 1.38), and further into metric units. It is reproduced in this report as Drawing E-1. The shaded envelope

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Drawing E-1 follows

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on the line is a transformation of plus or minus one standard deviation of the original data. Within this range, from the lowest to the highest cost for given depth, the change in cost more than doubles. Even this generalization should be regarded only as a rule-of-thumb.

The individual components of drilling costs are complex. The sensitivity of the components can be deduced from Table E-1, abstracted

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Table E-1 follows

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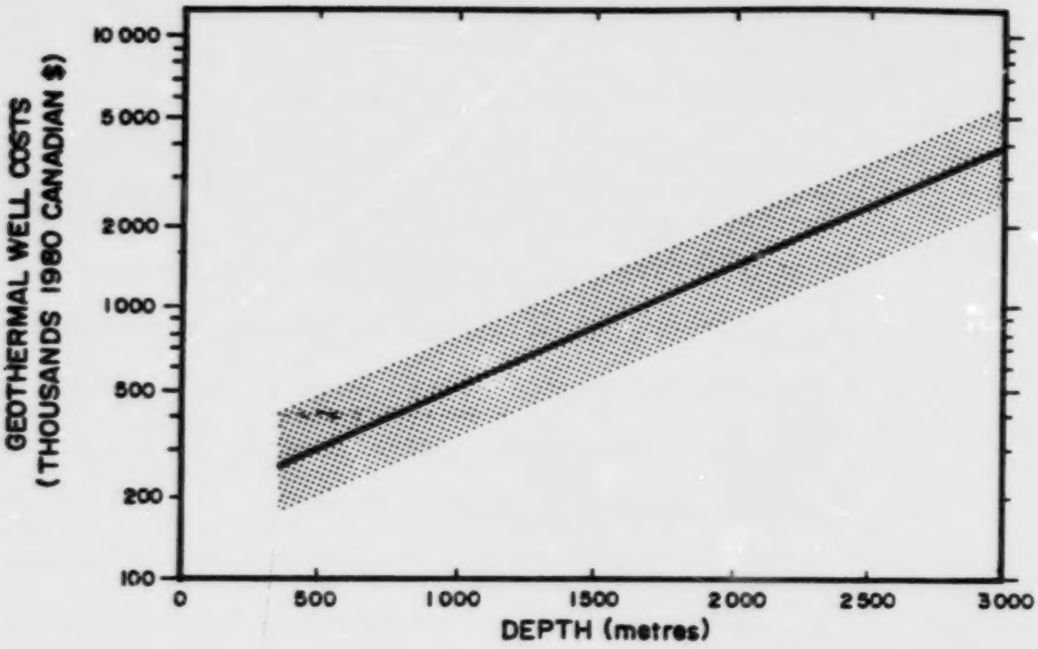
from the same source (Chappell et al, 1979).

E.2.2. Program Cost

If a determined explorer were to embark upon a systematic exploration program to discover a geothermal field capable of system-electric generating, he would be faced with a range of



DRAWING E-1

GENERALIZED WELL COST
AS A FUNCTION OF DEPTH
(adapted from Chappell et.al.)

Table E-1: Generalized Cost Components for Completed Geothermal Wells

Item	Cost (thousands of U.S.$)	Percent of Total
Site preparation	91	5
Mobilization and demobilization	91	5
Drilling (labour, fuel, rig)	564	31
Bits	73	4
Mud and chemicals	91	5
Cementing	291	16
Equipment rentals	91	5
Transportation	36	2
Supervision	36	2
Logging	55	3
Casing	164	9
Wellhead	36	2
Miscellaneous	200	11
Total:	1,819	100

(Basis rounded weighted averages of two industry wells, and Raft River 5 and INEL 1, as reported in Table II of Chappell et al , 1979. Depth range represented is 1 500 - 3 200 m.)

possibilities somewhat as shown in Table E-2 for

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Table E-2 follows

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the cost of discovery. The lowest conceivable cost for reaching his goal might be $4 000 000. The highest cost given approaches $20 000 000; but even an expenditure at that level does not guarantee success. The cost could exceed $20 000 000. The factors which determined whether the cost is low, medium or high might be outside the explorer's control.

At every turn the explorer will be faced with decisions on whether to abandon a prospect or a well, or whether to move toward a certain area or into a new area, or whether to proceed in spite of equivocal results. In some instances the decisions are difficult: "teasers" which are too good to abandon, but not good enough to proceed with more work.

There is a certain arbitrary nature to Table E-2. Each model suggests that the explorer takes a number of tries at a given activity and proceeds ahead after the last and the successful try. There is also an arbitrariness about our application of the model. In Section 4.0, for

Table E-2. Exploration Costs for Large-Scale Program Designed to Discover Geothermal Resources of System-Electric Capability

Exploration Stage	1980 Canadian dollars in thousands		
	Low Cost	Medium Cost	High Cost
Reconnaissance Areas:			
Cost each area	100	150	200
Number of attempts	x 1	x 2	x 3
Cost to select prospects	100	300	600
Prospects:			
Cost each program	500	750	1 000
Number of prospects	x 3	x 5	x 6
Cost to site wells	1 500	3 750	6 000
Deep Wells:			
Cost each well	1 200	1 600	2 000
Number of wells	x 2	x 4	x 6
Total for drilling	2 400	6 400	12 000
Total Cost of Discovery:	4 000	10 450	18 600

purposes of production cost analysis, we assume that $10 000 000 is the cost of discovery for a hydrothermal deposit, which is subsequently confirmed and drilled for production of 50 MW (net). We further assume that subsequent exploration at the margins of the 50 MW field costs $5 000 000, for each additional 50 MW of capacity. In assumptions on production costs, we assume that the exploration wells are not used for production; in actual fact, some would be.

E.3. Local Electric Exploration

E.3.1. The Conundrum

Geothermal exploration for local electric use may not be economically valid activity. This conundrum is familiar to developing countries with very high geothermal potential, but with scant or non-existent power grids. It applies equally to points in British Columbia which are far from system-electric service. The problem is:

1. The probability of success cannot be quantified;
2. The cost of discovery cannot be predicted, and the theoretical cost of discovering a small field might approach the theoretical cost of discovering a large field ($20 000 000 or more);

3. All of the exploration cost is at risk;
4. The value of a limited amount of usable or marketable energy may not be worth the gamble.

There are only four partial solutions to this economic bind:

1. Some unique factor, such as a super-boiling hot spring indicates an obvious hydrothermal resource, and enhances the probability for successful discovery (targets in British Columbia are concealed);
2. The high risk exploration funding is provided at no cost by an external economy (e.g. foreign aid program, tax deferred funds, etc.);
3. In discovering a small field, the possibility exists that the ultimate capacity of the field could be large and that the energy could be supplied to a future grid, marketed to a larger system, or would attract relocation of a major consumer;
4. If the program is a qualified success and discovers a low temperature resource, the energy can be utilized or marketed for

direct-use purposes, or future technology will provide the means for converting low temperature energy into electricity.

E.3.2. Exploration Cost Model

A cost model for a small-scale exploration program is given in Table E-3. It is derived from

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Table E-3 follows

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a previous study by Nevin Sadlier-Brown Goodbrand Ltd. for a developing country caught in a small-scale conundrum. It has been revised and re-estimated for site-specific application in remote parts of British Columbia. The cost estimates assume that the operator cuts every possible corner in an effort to economize. The low cost model is approximately $1 000 000 and the high cost model is about $5 000 000. The difference between the lowest and the highest costs is partly outside the explorer's control, however, specific costs to accomplish given tasks could be estimated at the start of a program and refined during the course of a program. In other words, a distinct cut-off point could be established for expenditures. The explorer could determine that, if no

Table E-3. Exploration Costs for Small-Scale Program Designed to Discover Geothermal Resources of Local-Electric Capability

A. Definition of Cost-Case

Low Cost: Outstanding prospect; sequence of activities shortened, geophysics abbreviated or omitted; low-cost logistics; discovery presumed after one 1 500-meter well; rapid achievement of success.

Medium Cost: Targets not obvious within prospect; use most steps; certain logistical support costs; drilling deeper and more difficult; assume discovery after two 1 500-meter wells; success reached in "normal" time period.

High Cost: Obscure targets; all steps used and repeated; remote terrain; drilling still deeper and more difficult; assume discovery after three 2 000-meter wells; delays and slow progress--time-dependent physical and interest costs mount.

B. Unit Costs

	1980 Can $ in thousands		
	Low	Medium	High
Geology, geophysics, chemistry, hydrology	65	117	195
Resistivity surveys or other geophysical surveys	39	97	195
Shallow drilling	45	104	156
Deep drilling	715(1)	1560(2)	3900(3)
Administration, logistics, permitting	91	195	390
TOTAL:	955	2073	4836

C. Notes

(1) 1 well x 1 500 m x $477/m = $715 500

(2) 2 wells x 1 500 m x $520/m = $1 560 000

(3) 3 wells x 2 000 m x $650/m = $3 900 000

Drilling costs are all-inclusive (mobilization, logging) and unit costs lie within the lower range of the cost "band" shown in Drawing E-1.

promise of commercial success existed after the expenditure of $1 500 000, for example, the program would be terminated.

As for the system-electric conceptual program, no provision is made for lease payments or other purchase of geothermal exploration and development rights.

In Section 5.0 the exploration costs given are combined with low, medium and high-cost models for plant development and are fixed.

E.4. Direct Use

Exploration and drilling for direct use applications has a wide range of cost elements. At the low-cost end of the spectrum it is very much like drilling ordinary water wells. Table E-4 indicates the cost elements which

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Table E-4 follows

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may go into a shallow cable-tool well. The unit costs given should allow the interested reader to calculate an approximate cost of a specific project.

At the high-cost end of the spectrum, an oral survey of panelists at a direct-use symposium in 1979 produced the figures given in Table E-5. Generally, the

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Table E-5 follows

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Table E-4. Generalized Typical Drilling Costs for 250 mm (10-inch) Hot Water Well, Depth 70-200 m, Cable Tool Rig

Mobilization and demobilization	$1 000
Drilling, crew, fuel, per meter	130
Liner, per meter	40
Other material, per meter	70
Subtotal per meter:	$ 240

All costs vary ±50% or more depending on local conditions, overburden and rock type, liner needed, etc., in 1980 Canadian dollars.

Table E-5. Poll of Panelists of U.S. DOE Symposium on Direct Heat Applications, held at Geothermal Resources Council Annual Meeting, Reno, September 1979, on Costs of Wells Recently Drilled and Completed (converted from feet to meters)

Project		Depth (m)	Cost (US $) in thousands	US $/m
1.	Production	2 591		
	Reinjection	1 219		
	Total	3 810	$ 400	$ 105
2.	Production	1 184	200	169
	Test	812	67	83
	Total	1 996	267	134
3.		430	64	148
4.		1 300	277	213
5.		640	285	445
6.		66	58	879
	TOTALS:	8 242	$1 351	
	Average cost per meter			$ 164 (US)

wells noted are deep, the deepest at about 2 600 meters. Most were drilled with rotary tools.

These data are summarized and generalized in Drawing E-2, an approximation of well costs as a function

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Drawing E-2 follows

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of depth. (The costs shown in Drawing E-2 merge with those from Chappell, Drawing E-1, where the depths become the same.)

A drilling cost analysis was done by Brown (1979), which compared the costs of drilling geothermal wells in the Madison limestone with completing unsuccessful oil wells for geothermal production, or reworking old oil wells. The results are given in Table E-6. If dis-

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Table E-6 follows

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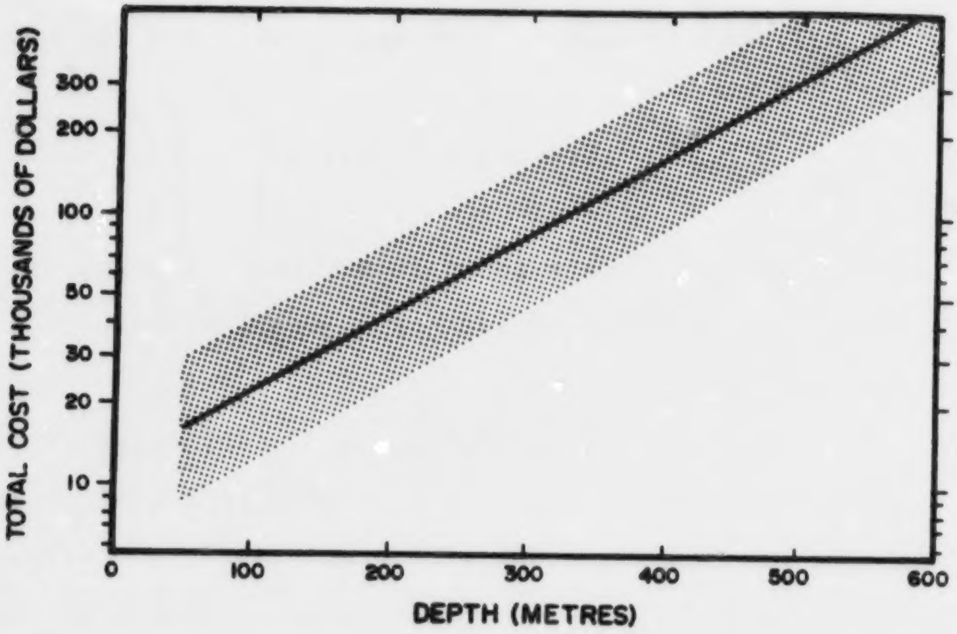
tribution and utilization of thermal energy is feasible, use of oil wells might provide the resource at 10 percent to 50 percent of the cost of new wells.

Since the cost of exploration and drilling is the principle pre-production cost for direct use geothermal applications an examination of a drilling cost per unit



DRAWING E-2

GENERALIZED DRILLING AND CASING COSTS FOR A HOT WATER WELL LESS THAN 150°C

Applies to cable-tool well cased to 250mm (10-inch) diameter to 200m; or rotary well cased to 75-150 mm (3-6 inches) below 150 m.

TABLE E-6. Cost Estimates for Developing Direct Use Wells 1524 m Deep in Madison Limestone, in Montana, Wyoming, North Dakota, and South Dakota (converted from feet to metres; from Brown, 1979)

	U.S. Dollars in Thousands (except averages)		
	Drilling New Well	Completing Unsuccessful Oil Well for Geothermal	Re-working Old Oil Well for Geothermal
Prefield Work			$ 1
Drilling and Logging	$150	Existing	$ 8
Casing Cost			
12" x 180 m	15	Existing	Existing
7" x 1524 m	90	$ 90	Existing
Set Casing	5	5	Existing
Cement	10	10	10
Perforation	10	10	10
Wellhead Equipment	2	2	Existing
Bond		10	
TOTAL	$282	$127	$29
Average per meter (in $)	$185	$ 83	$19

of thermal energy is in order. Table E-7 shows the

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Table E-7 follows

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flow from representative poor, fair and good water wells in various familiar units. If the water is hot and the heat is utilized down to a base temperature of 30°C, the content of thermal energy is also given in familiar units. These data are transposed into Draw-E-3 as continuous curves.

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Drawing E-3 follows

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The general range of thermal energy might be considered to be from 300-30 000 kilowatts (thermal) or from 1 000 000 to 100 000 000 kilojoules per hour. The temperature of a hot water well may range up to 150°C. (Above 100°C water boils at atmospheric pressure, however, some direct-use projects utilize waters at higher temperature under a confining pressure.) From the well cost information, a general range can be established between $10 000 and $1 000 000. Drawing E-4 combines the

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Drawing E-4 follows

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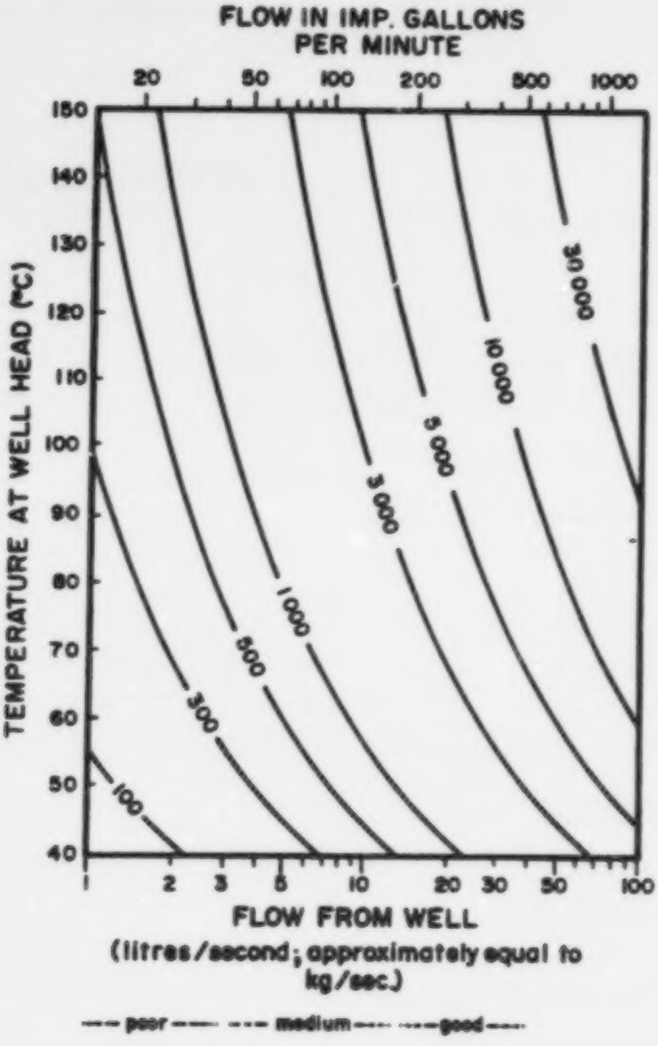
usable heat above 30°C, and the cost of the completed

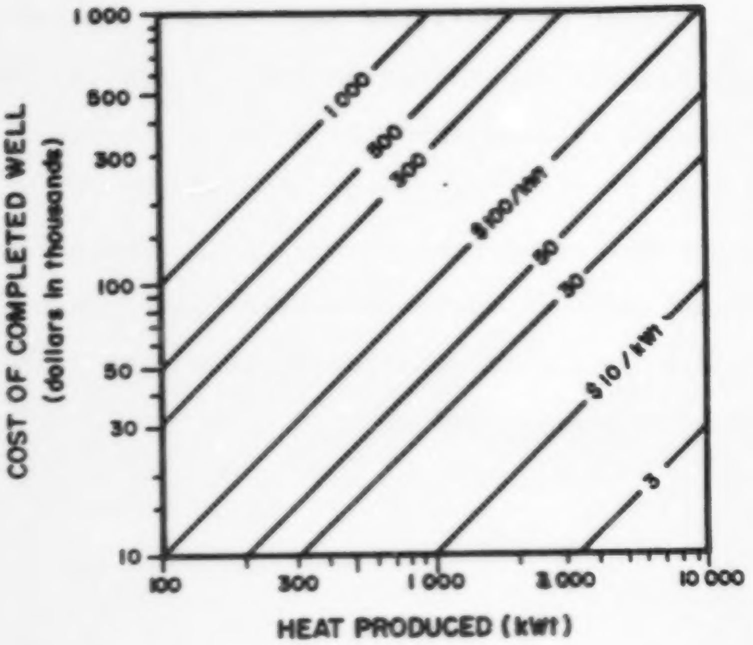
TABLE E-7. Typical Yields of Hot Water Wells (including rounded conversion to various familiar units)

	Quality of Production		
1. **Equivalent Flow Units**	**Poor**	**Medium**	**Good**
kg/hr	8 000	30 000	80 000
litres/second (L/s)	2	8	22
pounds/hour	18 000	60 000	180 000
gal (Imp) per min (gpm)	30	100	300
cubic feet per sec(cfs)	0.08	0.3	0.8
2. **Heat Content above 30°C**			
a. **at 75°C**			
kj/hour	1 500 000	5 700 000	15 000 000
kcal/hour	360 000	1 350 000	3 600 000
BTU/hour	1 400 000	5 400 000	14 000 000
kilowatts(thermal)	420	1 600	4 200
b. **at 150°C**			
kj/hour	4 000 000	15 000 000	40 000 000
kcal/hour	960 000	3 600 000	9 600 000
BTU/hour	3 800 000	14 000 000	38 000 000
kilowatts(thermal)	1 100	4 200	11 000



DRAWING E-3

HEAT CONTENT ABOVE 30°C FROM A HOT WATER WELL AT VARIOUS TEMPERATURES AND FLOW RATES, IN KILOWATTS (THERMAL).



DRAWING E-4

RANGE OF SCENARIOS OF
CAPITAL COST FOR DIRECT
USE HOT WATER GEOTHERMAL
WELL, EXPRESSED IN
$ PER KILOWATT (THERMAL)

well, to produce a range of capital costs under most anticipated conditions. The range is from $3.00 per kW(thermal) to more than $1 000 per kW(t). The median is $100 per kW(t), or 2.8¢ per kj/hour capacity.

Direct pre-drilling exploration expense is not specifically considered in these estimates, but its level is less than the error in the generalization of overall drilling costs. No charges for title to geothermal resources are included. The estimate for the capital cost of the energy bears directly upon the various models of utilization discussed in Section 6.0 and Appendices G and H.

APPENDIX F. PARAMETERS FOR ELECTRIC CONVERSION

F. PARAMETERS FOR ELECTRIC CONVERSION

F.1. Difference between Geothermal Plants and Conventional Thermal Plants

Conventional thermal plants convert the heat of combustion of a fossil fuel to shaft work and electricity. Most use water and steam as the medium for operating an expansion machine. In a complete cycle, water is heated in a boiler to steam at high pressure and temperature. The steam is fed to a turbine, driving the blades as it expands through the turbine, and exhausts into a low pressure condenser. From the condenser it is pumped back to the boiler to begin the cycle again.

The work done by the steam--expanding against a load--is done at the expense of its heat content. The loss of heat is accompanied by a concomittant drop in both temperature and pressure.

Most geothermal conversion systems utilize only the expansion part of the cycle, passing natural steam through the turbine and wasting or rejecting the remainder of the contained energy. Natural steam generally occupies a position of low temperature, low pressure, and low specific heat in comparison to man-made steam. Turbine diameters are proportionately larger to accommodate lower intake pressures and lower pressure drops. By conventional standards thermal efficiency is quite low.

F.2. Components

F.2.1. Wells and Well Fields

The elements of drilling and drilling costs are reviewed in Appendices D and E. The most sensitive are depth, type of rock, site characteristics, diameter, cost of completions and cost of mishaps.

The most sensitive performance factors of well fields are rates of flow, proportion of dry or lost wells, proportion of wells needed for waste disposal, frequency of redrilling or replacement required, and spacing between wells.

Each of these variables is different on the hydrothermal systems in the world which have system electric installations.

The rate of flow has a linear relation to the power which can be produced. An excellent dry steam well produces at about 150 000 kilograms per hour (kg/h). A moderate or good well might produce 50 000 to 90 000 kg/h. Below that level the well might be considered marginal depending on its depth, the production capability of nearby wells, and external economic factors.

Comparable figures for high temperature and high pressure hot water wells are 400 000 kg/h from an outstanding well, 200 000 kg/h from a moderate or good well, and 100 000 kg/h or less from a poor or marginal well.

Wellhead flowing pressure is 500 to 1 000 kPa for a good dry steam well. Separators installed on hot water wells produce a saturated steam component at about the same pressure. The fraction of steam varies according to fluid characteristics and equipment design; it is commonly 20 to 50 percent of the total flow.

The proportion of dry or lost wells might be outside the direct control of the operator. In some producing fields, dry wells are considered for use as disposal wells. The proportion of waste disposal wells may range from 1 for each 10 or 12 production wells in a dry steam field to about 1 for 1 if the field is a low grade resource.

As a rule of thumb, the geothermal industry considers 15 years to be the life of a production well. The principle cause for decline in performance is plugging of the well bore or the adjacent reservoir voids with mineral precipitates as the hydrothermal fluid expands and flows toward the wellhead. Corrosion, casing failures and cement failures are other causes. Well life may vary widely depending upon the characteristics of the fluid.

Replacement wells are generally drilled close to or between the original producers.

Production wells are generally drilled in a pattern determined by topography and inferred reservoir characteristics. Distances between wells vary from about 100 meters to about 500 meters, or in equivalent terms the area of withdrawal served by each well may vary from 10 000 to 250 000 square meters. Well spacing is established after practise in most fields so that adjacent wells have little or no drawdown influence on one another. In the design and construction of ambitious power projects, the well productivity and spacing impose an upper limit on the capacity of each turbine generator unit.

F.2.2. Gathering System

The gathering system is a network of pipes extending from individual wellheads, through manifolds and into the turbine generator plant. The aforementioned limit on plant size derives from practical limits on the extent of the gathering system. A steam transmission pipe which is too long will waste pressure and heat between the wellhead and the plant.

Separators are generally installed at or near the wellhead, and various other chambers for drying steam or for separating rock chips and particulate matter also comprise parts of the gathering system.

Large "U"-shaped loops are built into steam transmission pipe, and the pipes are laid on supports which allow movement. This construction is required to accommodate thermal expansion and contraction from periodic well shutdowns.

F.2.3. Power Plants

Power plant systems are expansion machines, generally turbines. Since there are several types and combinations of systems they are discussed in more detail in Appendix F.3.

F.2.4. Generating Systems

The conversion from shaft work to electrical energy is accomplished by means of generators, transformers, and switch gear. This equipment is essentially the same as that deriving power from any other type of prime mover. The only significant difference is that for equipment operating in an environment containing corrosive gases certain modifications must be made to protect brushes and contact points.

F.2.5. Transmission Lines

Transmission lines do not differ significantly from those required for a project of similar capacity. Because geothermal energy is site-specific, like hydro power, the cost and maintenance of transmission lines enter into the economic considerations of any particular project. Other than the assumptions made in Appendix F.6. for the economic analysis model of Section 4.0, transmission lines are not considered further.

F.2.6. Other Important Components

The characteristics of the site are important from the standpoint of the logistics of construction and operation. These include transmission distance, as well as the various civil engineering factors which enter into construction and the security of the field and plant. Such factors are the strength and stability of the underlying soil materials, the stability of adjacent slopes, the incidence of snow avalanches, characteristics of precipitation, protection from flooding or forest fires, and similar considerations.

The environmental considerations of geothermal resource exploration and utilization are not considered at length in this study. Each site is different, and different environmental effects may require mitigation. The principle environmental consideration in most geothermal electric developments concerns the method of disposal of hot liquid waste. Most projects in the planning stages in the United States design for reinjection of liquid waste into the reservoir by means of disposal wells. Disposal wells (also called reinjection or recharge wells) serve a secondary purpose of returning some of the waste heat to the reservoir.

At Cerro Prieto, Mexico, liquid waste is discharged into an artificial lake, and evaporates at the same rate.

The next most serious problem is the discharge of hydrogen sulfide gas (H_2S) into the atmosphere. Hydrogen sulfide is the "rotten egg" gas which has various adverse effects besides being noxious. It is heavier than air, it is combustable at temperatures of 250°C, and it is both acid and oxidizing. An exposure to more than 100 parts per million over a period of 15 minutes destroys the ability in humans to detect its odour, and in larger concentrations, about 500 ppm, it is lethal. Abatement procedures for H_2S are available. Not all geothermal fields have large quantities of H_2S but at the outset it is one of the impurities which may be expected.

F.2.7. Operating Personnel

Large geothermal plants are similar to hydro plants in requiring few operating personnel once construction is completed. Staff concerned with energy conversion are about one per 10-20 MW in developed countries, and several times that figure in lesser developed countries. For purposes of the economic models of Sections 4.0 and 5.0, operating costs are aggregate figures, not sensitive to labour costs.

F.3. Power Plant Systems

At the risk of putting the cart before the horse, five principal types of power plants are reviewed, then a non-mathematical treatment of the thermodynamics of geothermal resources is presented. It is the thermodynamic properties of the resource to which the power plant is matched in any given project.

Drawing F-1 consists of five separate figures,

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Drawing F-1 follows, in 5 parts
to be reduced and printed as one
page

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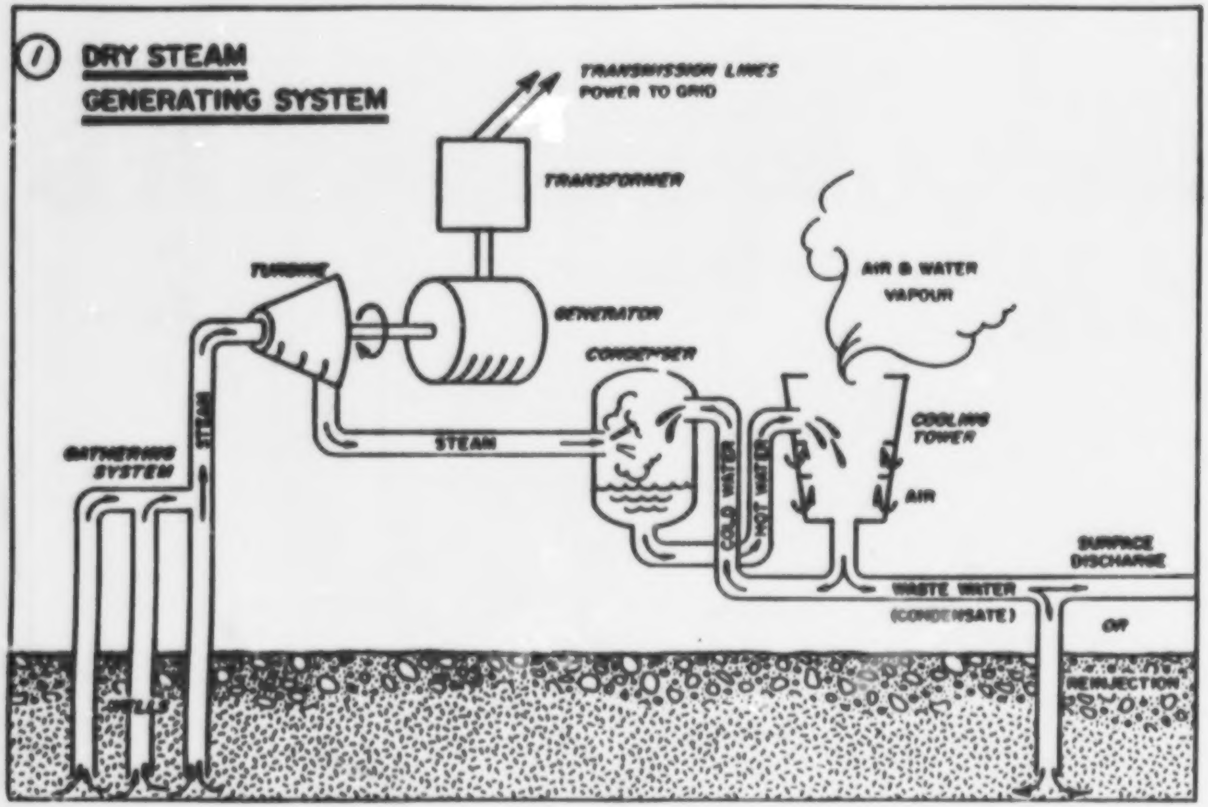
each representing a different system. Their

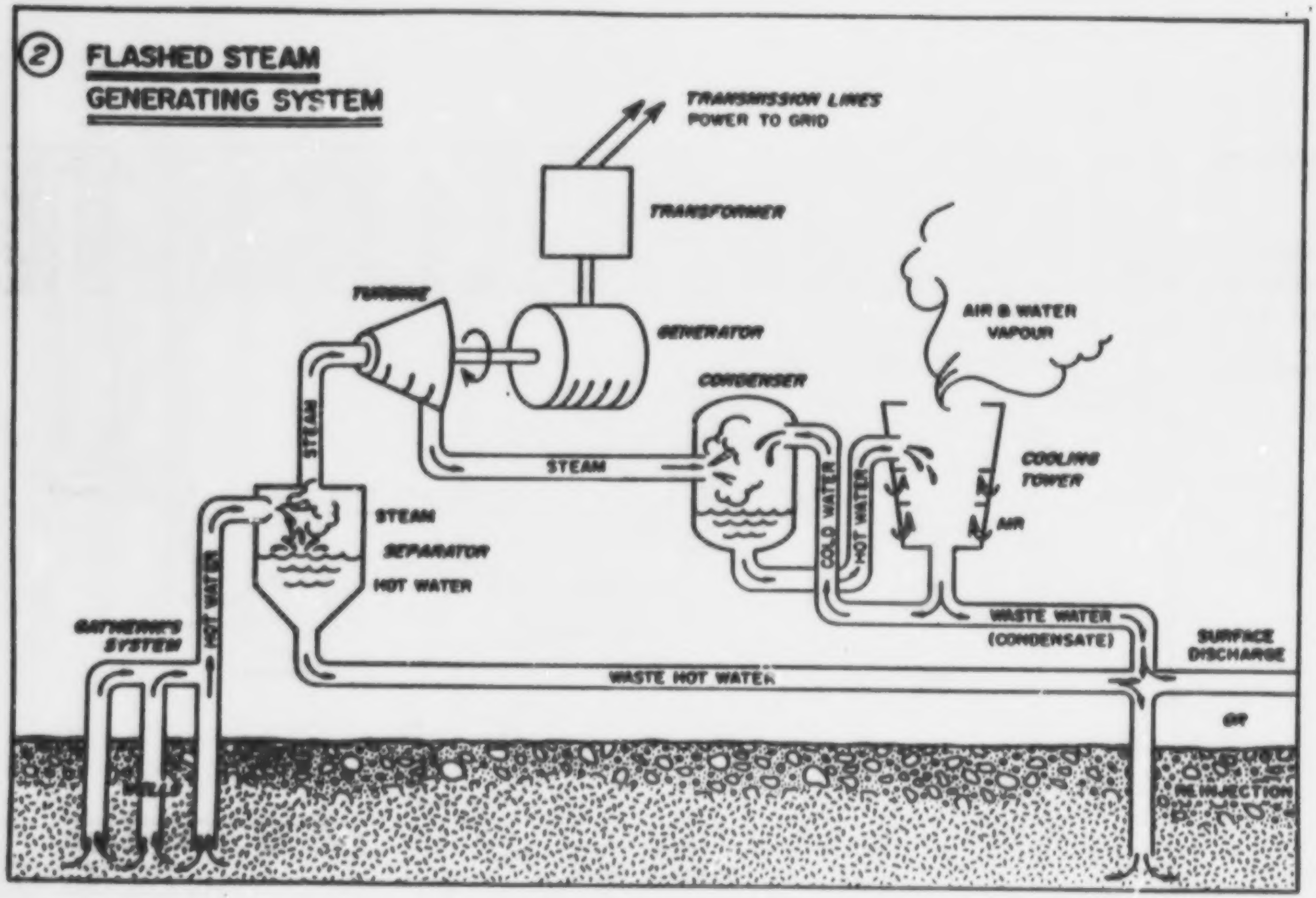

① DRY STEAM
GENERATING SYSTEM
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
AIR & WATER
VAPOUR
CONDENSER
COOLING
TOWER
GATHERING
SYSTEM
STEAM
STEAM
COLD WATER
HOT WATER
AIR
SURFACE
DISCHARGE
WASTE WATER
(CONDENSATE)
OR
REINJECTION
WELLS

DRAWING F-1

FIVE REPRESENTATIVE TYPES
OF GEOTHERMAL
GENERATING PLANTS

See text for discussion.

Continued overleaf ... /2

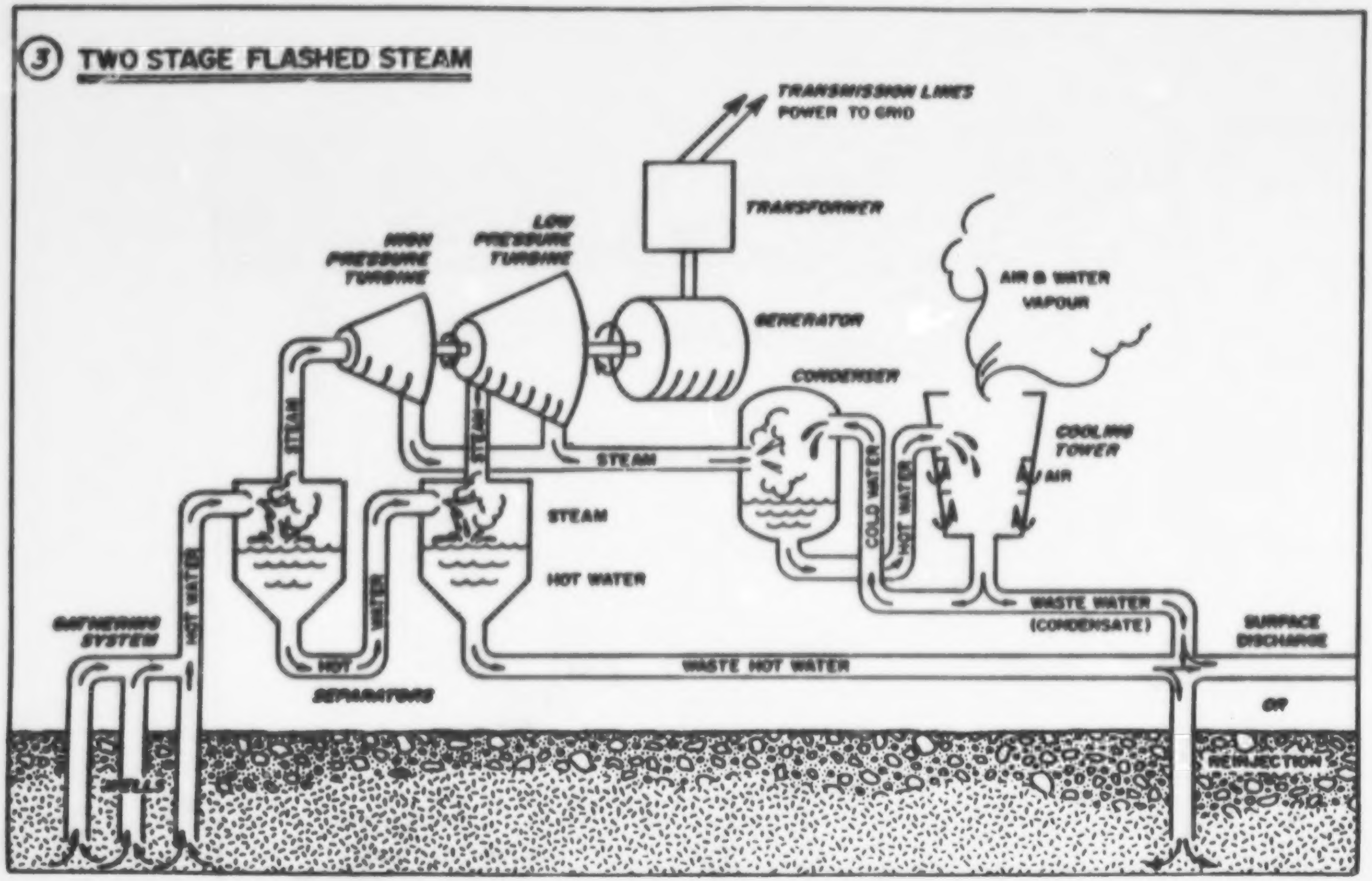


② FLASHED STEAM GENERATING SYSTEM

TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
AIR & WATER VAPOUR
CONDENSER
STEAM
COOLING TOWER
AIR
STEAM
STEAM
SEPARATOR
HOT WATER
COLD WATER
HOT WATER
GATHERING SYSTEM
HOT WATER
WASTE WATER
(CONDENSATE)
SURFACE DISCHARGE
WASTE HOT WATER
OR
WELLS
REINJECTION

DRAWING F-I (cont'd)

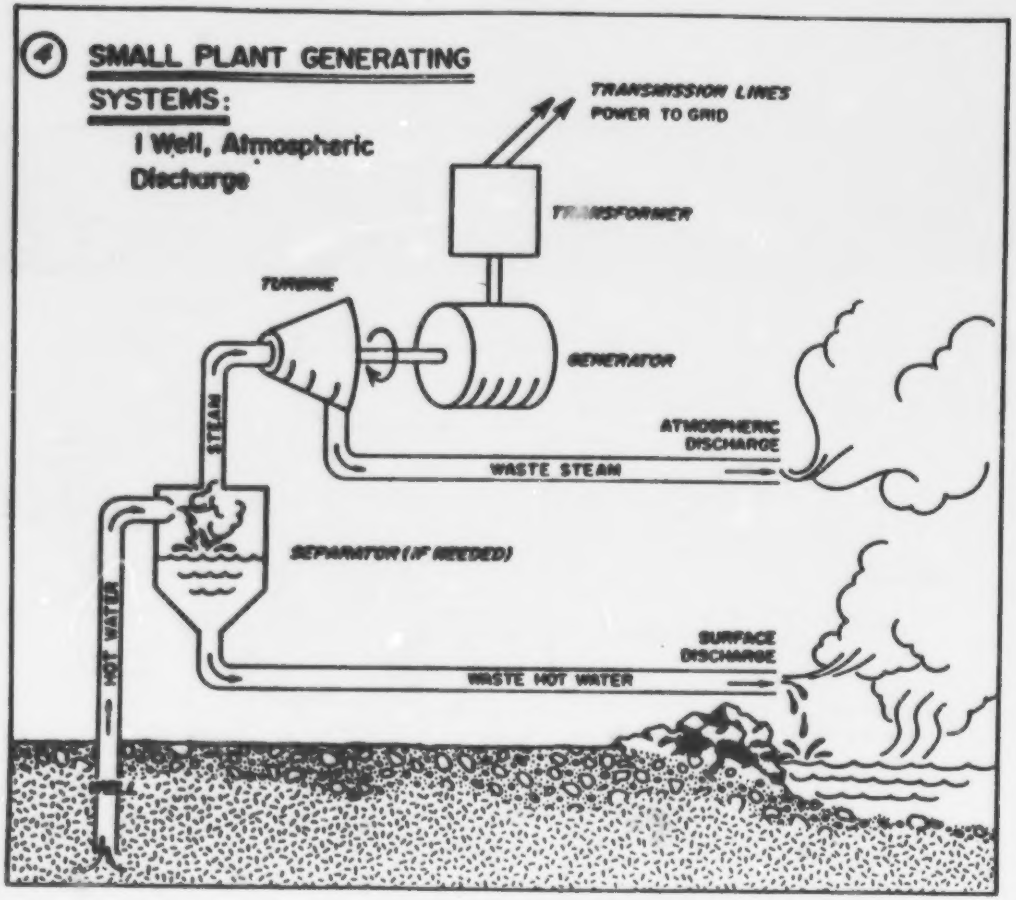
.../3


③ TWO STAGE FLASHED STEAM

TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
HIGH PRESSURE TURBINE
LOW PRESSURE TURBINE
GENERATOR
CONDENSER
AIR & WATER VAPOUR
COOLING TOWER
AIR
STEAM
STEAM
STEAM
STEAM
HOT WATER
COLD WATER
HOT WATER
HOT WATER
HOT WATER
WASTE WATER (CONDENSATE)
SURFACE DISCHARGE
OR
REINJECTION
GATHERING SYSTEM
HOT WATER
WATER
HOT
SEPARATORS
WASTE HOT WATER
WELLS

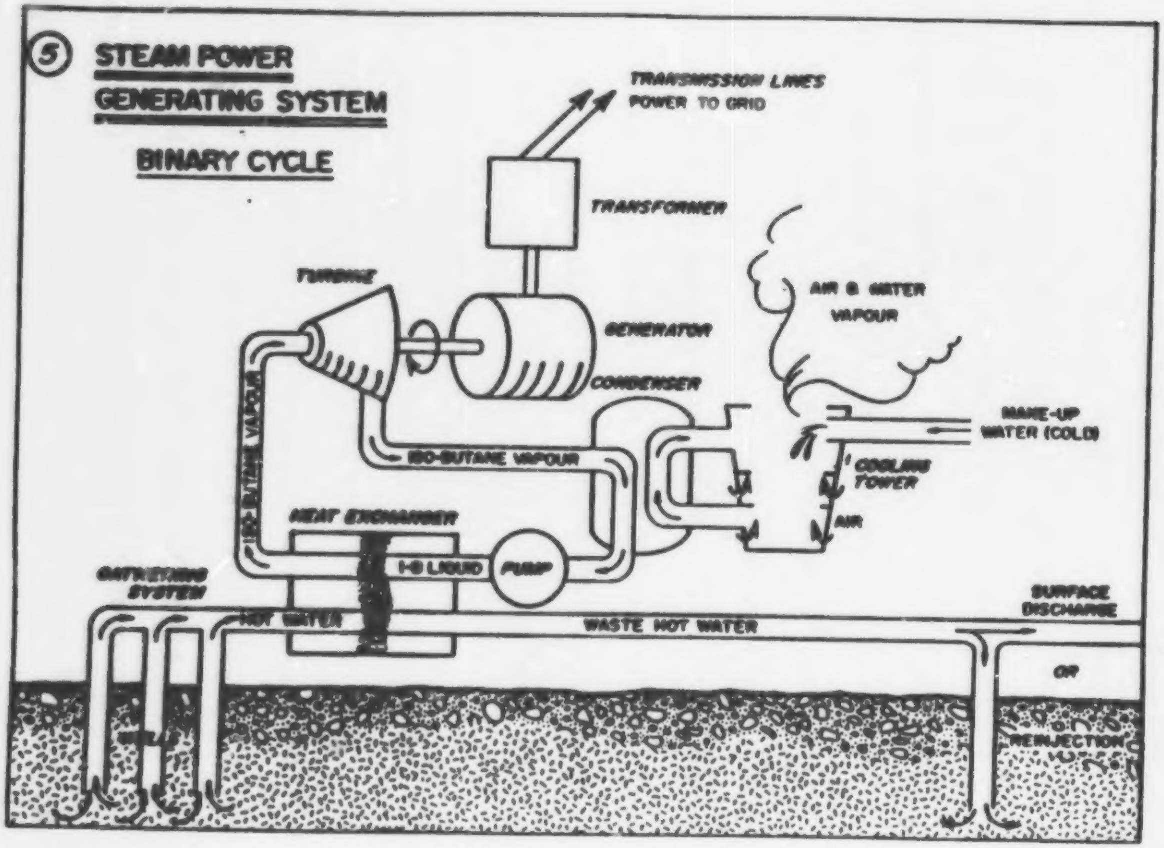
DRAWING F - I (cont'd)

.../4


④ SMALL PLANT GENERATING SYSTEMS:
1 Well, Atmospheric Discharge
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
STEAM
ATMOSPHERIC DISCHARGE
WASTE STEAM
SEPARATOR (IF NEEDED)
HOT WATER
SURFACE DISCHARGE
WASTE HOT WATER
WELL

DRAWING F-1 (cont'd)

.../5


5
STEAM POWER
GENERATING SYSTEM
BINARY CYCLE
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
CONDENSER
AIR & WATER
VAPOUR
MAKE-UP
WATER (COLD)
COOLING
TOWER
AIR
ISO-BUTANE VAPOUR
ISO-BUTANE VAPOUR
HEAT EXCHANGER
I-B LIQUID
PUMP
GATHERING
SYSTEM
HOT WATER
WASTE HOT WATER
SURFACE
DISCHARGE
OR
REINJECTION
WELLS

DRAWING F-1 (cont'd)

similarities and differences are discussed following.

F.3.1. Dry Steam Generating System

This system is used where a steam dominated reservoir is capable of producing dry steam at the wellhead. The steam passes directly from the gathering system into the turbine.

In the system illustrated in F-1(1) the steam expands through the turbine and into a condenser. The condenser is a closed vessel with an internal pressure approaching a vacuum. The vacuum is maintained by spraying cold water on the inflowing steam, absorbing its heat of vaporization, and condensing it from the gaseous to the liquid state (a "direct-contact" condenser). As liquid accumulates in the bottom of the condenser, it is removed by pumping.

The system shown then feeds the hot water to a cooling tower where its temperature is further reduced by giving up heat of vaporization to a certain fraction which enters the atmosphere. Depending upon many factors, the net loss to the atmosphere might be expected to be about 80% of the total mass produced from the wells. A small fraction is looped back through the condenser, and the surplus is either discharged on the surface or reinjected into a disposal well.

Plant efficiency is enhanced if cold makeup water for the condenser is pumped from a river rather than supplied by the cooling tower. The difference in temperature--say 5°C for a river in British Columbia, versus 50°C for water from the cooling tower--produces a lower temperature heat sink and allows the extraction of more energy.

The capacity of a geothermal generating unit may range up to about 135 MW. Capacities in the range 30-55 MW are common for units installed in the 1970's. At the Geysers, 55 MW units are paired in one building; 110 MW is the total plant capacity served by one gathering system.

Turbine rotor size for plants in the median range is about 1.5 to 2 m diameter at the low pressure (wide) end, with a shaft length of about 3-5 m.

F.3.2. Flashed Steam Generating System

A flashed steam system is used where the geothermal fluid is not naturally capable of producing dry steam at the wellhead. The principal difference between the flashed steam system of Drawing F-1(2) and the previously described system is that a separator is needed to extract a fraction of steam from a pressurized hot water resource. The separator is a closed vessel which has one inlet and two outlets. The pressurized hot water flows through an orifice, the size of which determines the pressure domain within the separator. Upon entering the lower pressure conditions of the separator, a portion of the hot water flashes instantaneously to steam. The steam flows out of an upper outlet, and the remaining water fraction out of the lower outlet.

Separating vessels may be two to five meters in height and one or two meters in diameter, with a shape much like a conventional cyclone separator. The steam produced is saturated, that is it lies exactly at the equilibrium point with water and tiny droplets of water may form incipiently upon a slight change in conditions. The steam needs to be dried before entry into the turbine. Drying may be accomplished by a further reduction in pressure, either in the gathering system or in a separate chamber.

In a single stage flash plant, the hot water fraction is wasted, either discharged on the surface, or reinjected.

F.3.3. Double or Multiple Stage Flash System

If the initial separation may be done at a temperature of 160°-175°C, considerable thermal energy remains in the hot water fraction. Plant output can be increased by adding one or more successive stages of separating, as shown in Drawing F-1(3), all at successively lower pressures and temperatures. The secondary steam products are fed into a lower pressure turbine, or at a lower pressure point in the main turbine.

The limit on the number of successive flashing stages which can be economically used is imposed by two factors. The first is the energy contained within the resource. The second is the capital cost of equipment and design complexities. At some point there is a diminishing return.

F.3.4. Non-Condensing Atmospheric Discharge Plant

Drawing F-1(4) illustrates a flashing plant which discharges to the atmosphere, without benefit of a condenser. In very general terms this is about one-half as efficient as a condensing system.

There are several reasons for considering such a plant. One would be if the proportion of non-condensable gases is too high to physically or economically maintain a vacuum in a condenser. The other reason, which is considered here, is that non-condensing units are simple and fundamental machines. Small non-condensing plants can be used for local electric generating or for initial pilot plant operation as part of a larger project.

Two manufacturers offer proven, small, non-condensing plants for sale in North America, Mitsubishi Heavy Industries, Ltd., Tokyo, Japan, and Geothermal Power Company Incorporated, Elmira, New York. These plants range from 1 500 kW to about 3 MW in capacity; they are modular, and can be easily transported by truck or railcar. A plant from Geothermal Power Company was installed in 1971 on the Kawah Kamojang Geothermal Field, Indonesia. This type of plant is considered in the discussion on the economics of local electric generating, Section 5.0.

Armstead (1976) presented some of the views favouring installation of a small modular plant on the first suitable geothermal well, even in a field being explored for large system electric potential. Rapid installation of a modular plant allows utilization of energy immediately, it serves as a pilot plant to study resource characteristics and establish procedures, and it dispels institutional skepticism which sometimes accompanies geothermal development projects. A small modular plant can be salvaged after service and transported to another site for the same purpose. Or, if engineering and resource characteristics permit, a condenser can be added at a later date.

7.3.5. Binary Systems

In some instances the geothermal fluid is not used as the working fluid, but as the heat source. The geothermal resource is extracted, put through a heat exchanger where the working fluid is boiled, and discharged or returned to the reservoir. Pure water may be used as the working fluid in instances where the geothermal resource is a concentrated brine. More commonly the working fluid is a hydrocarbon or fluorocarbon which has an extremely low boiling point. Some of the gases used as working fluids are iso-butane, propane and freon.

The anticipated benefit from binary plants is their ability to convert lower temperature geothermal energy to electricity than would be possible by direct drive systems.

The largest binary plant currently in operation is an 11 MW plant at East Mesa, California. Magma Power Company is the operator and holds patent on the process. Two working fluids are used, propane and butane. The reservoir temperature is in the range of 175 to 200°C. The operators are working toward the point where temperatures of less than 150°C, well below the current threshold, can be used economically for conversion to electric power.

Binary systems may be of future interest to British Columbians to resolve the small-scale exploration conundrum reviewed in Appendix E. Binary plants might provide a future ability to utilize low grade geothermal resources in remote locations.

F.3.6. Other Plants

The first geothermal electric plant in North America was a small reciprocating steam engine which is currently rusting in a shed at the Geysers field in California. In common with all such engines, it utilized the expansion of the natural steam.

Other plants which are under development are a screw expander turbine (by Jet Propulsion Laboratories), a Wankel-type of rotating displacement piston, and systems capable of handling mixed water and steam flow, either along the shaft such as with a conventional steam turbine, or tangential to the shaft, as with a large blower.

Conceptual ideas also include hybrid plants. These may be combinations of coal and geothermal, or wood chip and geothermal plants.

F.4. Resource Properties

F.4.1. Principles of Heat, Temperature, Pressure and State

Reference is made again to Drawing C-5, the relationship which exists between the various properties of water in the range that geothermal fluids are likely to occupy. At the pressure and heat content conditions on the left side of the drawing the fluid exists as water. To the right of the curve the fluid exists as steam. Under the curve water and steam exist together in equilibrium, with the relative amounts of each indicated. If heat is added to a given quantity of water at a specific pressure, the path traced on the drawing is to the right, the heat is stored as heat of vapourization without any increase in temperature, until the entire mixture becomes steam. Above the closed curve, or above the "critical point", no heat of vapourization is required to perform the same task, and the distinction between the properties of water and steam disappears.

As discussed in Appendix C, natural hydrothermal systems of a commercial nature tend to occupy either of the two fields shown. Steam dominated reservoirs exist at a temperature of about 230-240°C and a pressure of about 3400 kPa. The specific heat (enthalpy) is about 2800 kJ/kg, and the state is saturated steam, or steam coexisting in equilibrium with water.

Hot water systems, if they are commercial, tend to have higher temperatures and pressure than steam systems. They nonetheless have lower enthalpies, perhaps 1 000 to 1 500 kJ/kg.

The thermodynamic path of the fluid which flows up a well bore is very close to being adiabatic, that is, without loss of thermal energy. In Drawing C-5 this path is straight down. For the steam dominated system, this means that a wellhead pressure of about 1 000 kPa goes hand-in-hand with a temperature of 190°C. Similarly, a wellhead pressure of 500 kPa and temperature of 180°C coincide.

The inverted "T" shaped arrows in Drawing C-5 describe the path of the fluid from a hot water reservoir. The fluid ascends up the well bore into a separator along the downward path described by the vertical arrow. Upon entry into a chamber of 1 000 kPa pressure, the fluid fractionates, 80% as water and 20% as steam, both at about 180°C. The steam is saturated and will need another drop in pressure for drying. The drop in pressure implies a concomitant drop in temperature.

The pressures at the turbine intake vary from plant to plant, but after drying and expansion in the gathering system, they range from about 100 to 500 kPa.

The resources which have reservoir pressures and enthalpies lower than the patterned area (Drawing C-5) might be sub-commercial at the present time.

F.4.2. Available Heat, Work, and Loss

Only a fraction of the total heat in a geothermal fluid can be converted to electricity. Drawing F-2 is a schematic diagram showing the various types of energy loss. In a flashed steam system, the thermal energy contained in the water fraction is one component of the loss. The heat

- - - - - - - - - - - -

Drawing F-2 follows

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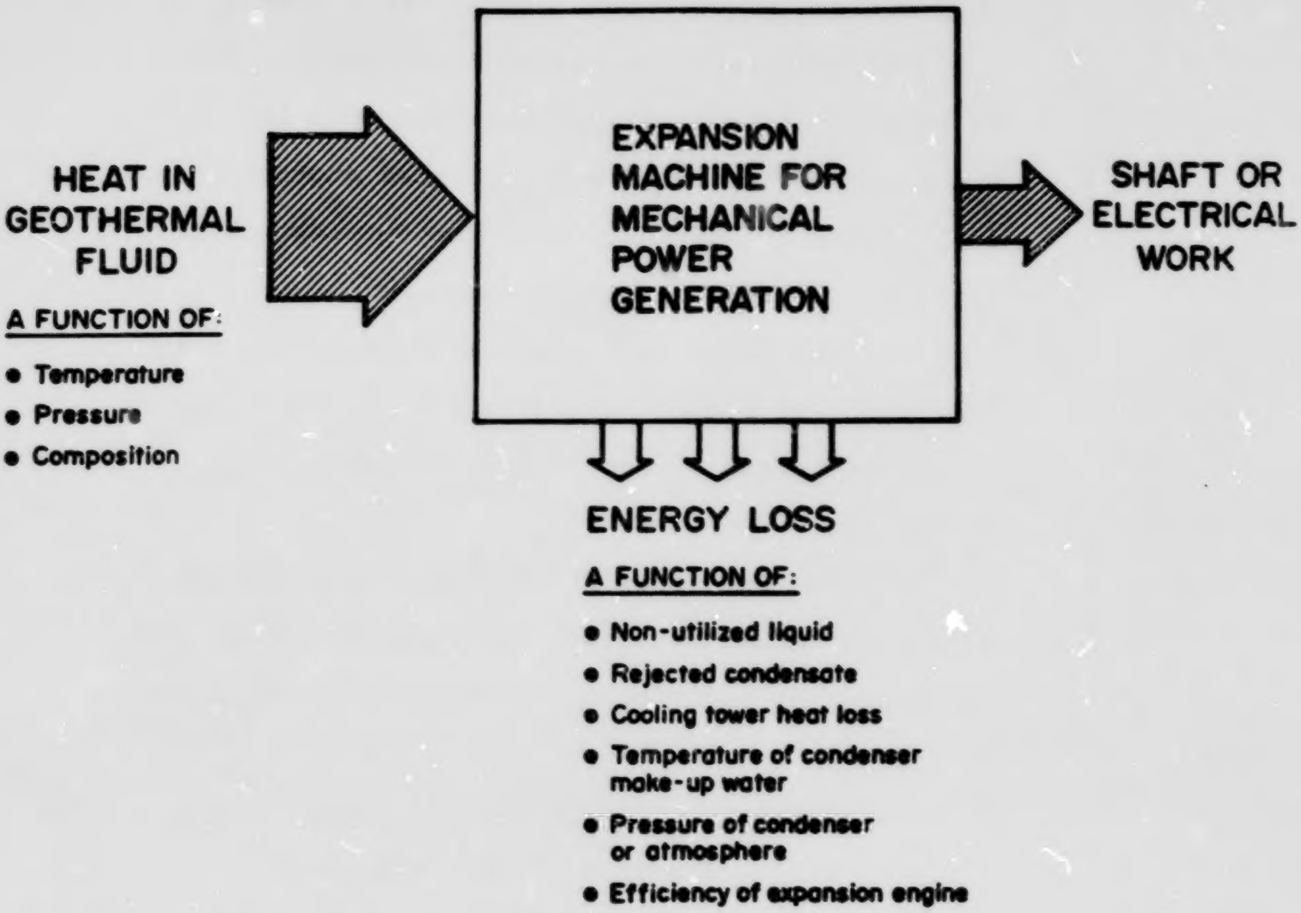
HEAT IN GEOTHERMAL FLUID
A FUNCTION OF:
• Temperature
• Pressure
• Composition
EXPANSION MACHINE FOR MECHANICAL POWER GENERATION
SHAFT OR ELECTRICAL WORK
ENERGY LOSS
A FUNCTION OF:
• Non-utilized liquid
• Rejected condensate
• Cooling tower heat loss
• Temperature of condenser make-up water
• Pressure of condenser or atmosphere
• Efficiency of expansion engine

DRAWING F-2

GENERALIZED BALANCE OF ENERGY INPUT AND OUTPUT OF A GEOTHERMAL POWER PLANT lost from cooling towers is another.

There are several other causes of energy loss within a plant, including friction, efficiency of the turbine, and the energy required to drive internal pumps, motors, fans, compressors and the like.

Conventional thermal plants measure efficiency by comparing the energy output to a loss called "rejected heat". The open nature of geothermal conversion systems is such that a different index of efficiency is used. The energy output is compared to available energy. Efficiency may range from a high of about 50% down to a level of 20% or less. The reader is referred to DiPippo (1980) and Wahl (1977) for the mathematical treatment of the energy balance in geothermal plants. Those authors and Diment et al (1975) discuss efficiency.

F.4.3. Generalized Conversion Parameters

The fraction of a hot water resource convertible to steam under various conditions of enthalpy and separator pressures is generalized in Drawing F-3, prepared from a variety of sources.

- - - - - - - - - - - -

Drawing F-3 follows

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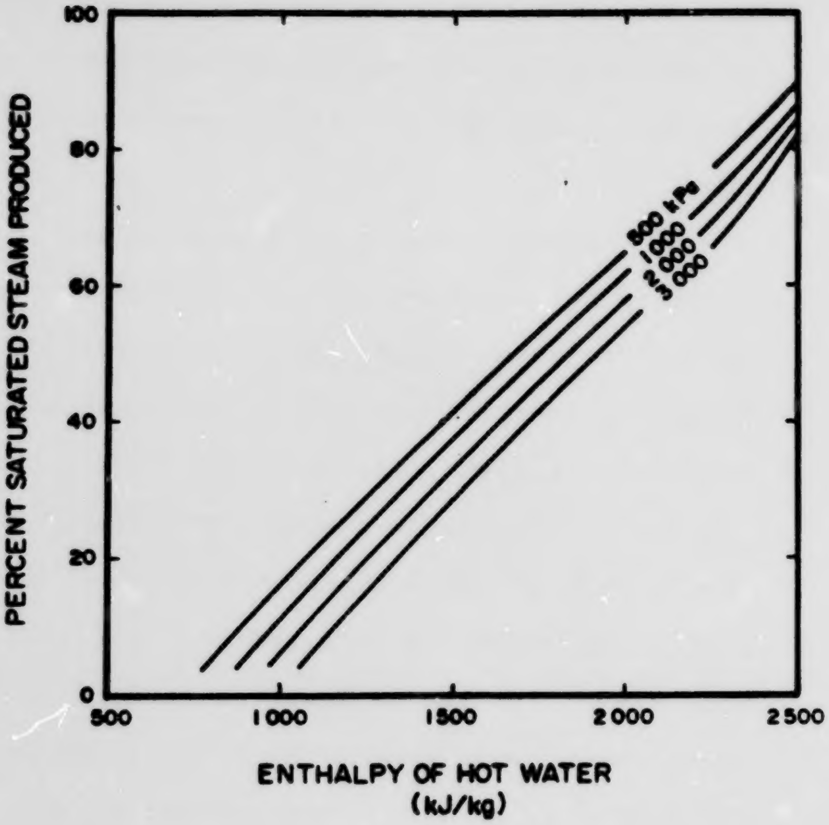
This provides a basis for comparing a hot water



DRAWING F-3

AMOUNT OF SATURATED STEAM PRODUCED AT NORMAL RANGE OF SEPARATOR PRESSURES FROM VARIOUS HOT WATERS.

resource to a dry steam resource. To calculate the power potential of a given well, one would have to know its rate of production and the pressure and enthalpy (or temperature) at the wellhead. The fraction of saturated steam could then be calculated using Drawing F-3.

The exercise is continued in Drawing F-4,

- - - - - - - - - - - -

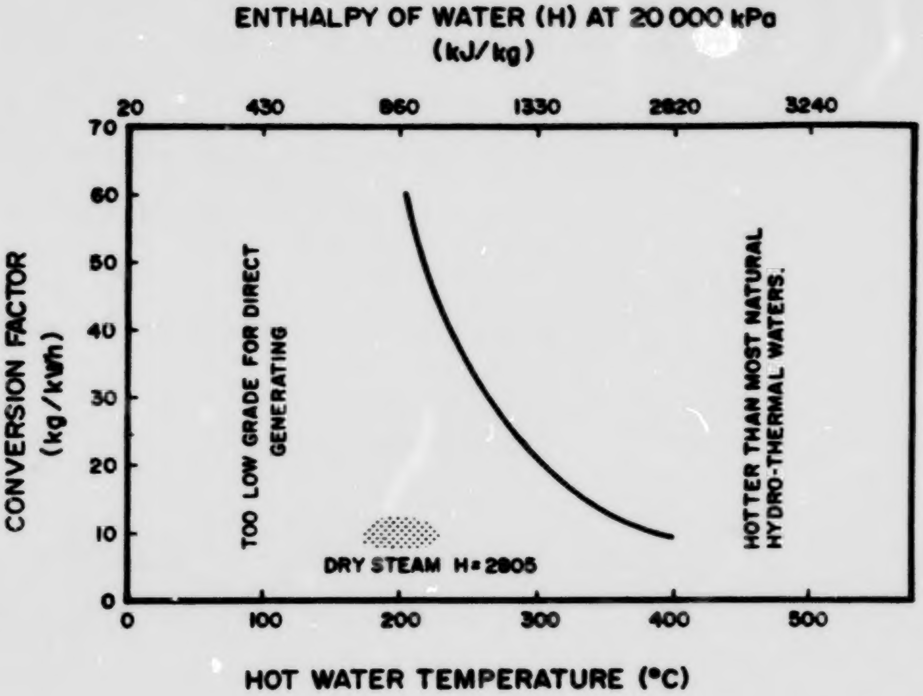
Drawing F-4 follows

- - - - - - - - - - - -

an approximation of the number of kilograms of hot water at varying conditions (dry steam is also shown) required to produce one kilowatt hour of electrical energy. As a very general rule of thumb eight to ten kilograms of dry steam are required per kilowatt-hour. The hot waters shown are representative of reservoir conditions, not wellhead conditions. The implication is, for example, that a hot water reservoir at 300°C requires about twice as much wellhead mass per kilowatt hour as does a dry steam resource. It should be emphasized that Drawing F-4 is a summary of complex resource properties and plant characteristics, and in any given instance the power production may require more or less geothermal fluid.

F.4.4. Depletion

Hydrothermal reservoirs are depleting



DRAWING F -4

HOT WATER REQUIRED PER KILOWATT HOUR AT VARIOUS TEMPERATURES.

Generalized curve for double flashing cycle. Reference enthalpy and dry steam resource are shown.

resources. The heat stored in the rock and water system which constitutes the reservoir is finite. Where heat is withdrawn for system electric or local electric applications, the rate of withdrawal exceeds the rate of input, except under very unusual conditions. With time, the reservoir will cool, the heat contained in the geothermal fluid at the wellhead will begin to decline, and ultimately the point will be reached where conversion is uneconomical or unfeasible using standard technology.

Very broadly speaking, the span of time required to deplete the thermal energy in an average hydrothermal reservoir far exceeds the time required to amortize the investment in plant facilities. In any given time-specific case, the properties of the reservoir can be measured via exploratory and production wells and the characteristics of thermal decline can be projected and planned decades in advance.

Depletion or overdraft of fluid also take place if production exceeds natural and artificial recharge. When this happens operating pressures begin to decline. Once again, fluid depletion is quantifiable in advance of its occurrence, given sufficient data and investigation.

The art of reservoir hydrology and engineering is sufficiently advanced that steps can be taken under some circumstances to mitigate depletion if necessary. Liquid waste could be reinjected into the path of the natural recharge groundwater, returning fractions of the withdrawn fluid and thermal energy.

F.5. Significance of Impurities

Rock chips may accompany steam or hot water flow from the well bore. Removal of chips is relatively simple and is accompanied by means of a cyclone type of separator in the steam line.

High temperature hydrothermal fluids generally contain dissolved silica in amounts in excess of 200 parts per million. Upon reduction of temperature and pressure, the silica becomes less soluble and tends to precipitate along the walls of pipes and at certain points within the gathering system. In extreme cases silica may coat turbine blades and lead to drag, inefficiency and imbalance. Silica precipitation may be partially controlled by adjusting the points of pressure drop so that precipitation occurs in the least troublesome area -- say, a chamber or a loop designed for periodic maintenance. In some plants, turbines are periodically shut down and the silica is removed from the blades by hand chipping.

Dissolved salts can reach such concentrations as to make a field non-economic. In a flashed steam system, most of the salt remains in liquid fraction, but some salts may remain dissolved in the steam fraction. Some of the resultant solutions are both acid and oxidizing. Materials in contact with the solution are generally designed to be resistant to corrosion.

Non-condensable gases primarily impair condenser efficiency. Vacuum pumps are used to remove these gases from condensers and reject them into the atmosphere. As previously mentioned, such gases include carbon dioxide, hydrogen sulfide, methane in minor amounts, argon, radon, and several other trace elements. DiPippo (1980) has an extensive discussion of the effects of non-condensable gases on plant and condenser design.

The most serious of the non-condensable gases is hydrogen sulfide. Generally environmental standards, not mechanical engineering standards, determine that H_2S should be removed from the constituents discharged into the atmosphere. If this is the case, there are several systems available for H_2S removal, the best known being the Stretford system which scrubs H_2S by means of a series of chemical reactions. In order to employ the

Stretford system a shell and tube condenser are needed rather than the less expensive direct contact condenser. Once again the reader is referred to DiPippo (1980).

F.6. Models for Economic Analysis

F.6.1. Reference Cases

Three reference cases are constructed for a range of geothermal field conditions, as shown in Table F-1. Case 1 represents a dry steam

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Table F-1 follows

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field similar to the Geysers; Case 2 is a high-temperature (270°C) liquid-dominated field similar to Valles Caldera, New Mexico, or Roosevelt, Utah; and Case 3 is a moderate-temperature (180°C) liquid-dominated field similar to East Mesa, California.

In all three cases, it is assumed that the geothermal fluid will be favourable in terms of low salinity, low non-condensable gas content, relatively shallow well depths (1 500-2 000 m) and low H_2S content (no abatement necessary).

The unit energy available at the wellhead decreases sharply going from Case 1 to Case 3.

TABLE F-1. Reference Cases for Economic Analysis

	Case 1 Dry Steam	Case 2 Hot Water	Case 3 Moderate Temp. Water
Reservoir Conditions:			
- Temp, °C	240	270	180
- Press, kPa	3 400	10 000+	10 000+
Wellhead Conditions:			
- Quality, % steam	100	20-35	0
- Enthalpy, kJ/kg	2 790	1 200	770
- Max. available energy, kJ/kg (1)	880	305	150
Plant Type	Conventional Steam	Single or Double Flash	Binary
Resource utilization efficiency - % (2)	51	40	40
Power conversation rate kg/kWh	8	30	60

(1) Clear water, sink temp. 15°C

(2) Plant output divided by maximum available energy.

With Case 1 the fluid is essentially all superheated steam. Case 2 has a mixture of 20 to 35 percent saturated steam with water. Case 3 has pressurized water, assuming wellhead conditions are controlled to prevent flashing.

F.6.2. Production and Reinjection Wells

Geothermal fluid requirements range from a low of 8 kg/kWh for Case 1 to a high of 60 kg/kWh for Case 3 (from Table F-1). Well production is assumed to be 90 000 kg/hr for Case 1 and 180 000 kg/hr for each of Cases 2 and 3.

For 50 MW(net) plants under the three cases, spare well allowance of 20 percent is included. The ratio of reinjection to production wells is based on estimates of return water flows. With Case 1, approximately 17 percent of the steam flow to the plant will be reinjected; the Case 2 estimate is based on approximately 65 percent direct return after flashing and a further return of 6 percent from the power plant; with Case 3, all of the geothermal fluid would be reinjected because a binary cycle plant is envisaged. The number of wells needed is given in Table F-2.

- - - - - - - - - - - -

Table F-2 follows

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TABLE F-2. Well Requirements for 50 MW Plant

	Case 1	Case 2	Case 3
Well flow rate, tonnes/hr/well	90	180	180
Production wells, including spares	6	10	20
Reinjection wells	1	7	20
Total Wells:	7	17	40

F.6.3. Gathering Systems

The design of the gathering system will be site-specific and will depend on well production, fluid properties and plant cycle parameters. No consideration has been given to design of the gathering system for this study. Typical costs of gathering systems have been used in the economic analysis.

F.6.4. Power Plants

The power plant for Case 1 will employ conventional steam plant technology, similar to the Geysers project, consisting of a turbine-generator set, direct contact condenser and mechanical-draft wet cooling tower.

The Case 2 plant could be either "single-flash" (separated steam) or "double-flash" (separated steam/hot water flash), depending on the quality of the geothermal fluid.

Various steam cycles have been considered for geothermal fields similar to Case 3, including binary cycles and double or multi-flash steam cycles. Economic studies of the alternatives generally favour a binary cycle at these lower reservoir temperatures.

The main advantages of a binary cycle for low temperature resources involve smaller turbine sizes and higher resource utilization efficiencies than corresponding flash cycles. These advantages tend to be offset by high costs of heat exchangers and additional costs associated with the working fluid.

F.6.5. Transmission

Transmission system requirements will be site-specific, depending on the location of the plant and the characteristics of the regional transmission system. For purposes of this analysis the assumption is made that the site is 75 km from an existing transmission corridor. The assumption is further made that the corridor includes a 230 kV line suitable for transmission of power from the model plant.

F.6.6. Timetable

The assumption is made that exploration, field development, feasibility studies and construction are conducted in the period 1981-1990, and that the first 50 MW(net) is on-line in 1991. The period of operation is the 25 years from 1991-2015, inclusive.

F.6.7. Economic Analysis

The analysis of system electric generation at the level of 50 MW is given in Section 4.0 of this report. Also considered is incrementation of development rapidly from 50 MW to 400 MW(net) at the same site.

G. DIRECT USE OF GEOTHERMAL RESOURCES

G.0. DIRECT USE OF GEOTHERMAL RESOURCES

G.1. Review

"Direct use" of geothermal resources means the utilization of heat--without conversion to electricity--for space heating, agriculture, or industrial processes. Projects on-stream throughout the world (Section 2.0) supply about 7 000 MW(t) to various users.

Characteristics of resources, including those limited at present to direct use, are noted in Appendix C. Resorts, known hot springs and potential producing areas in British Columbia are presented in Section 3.0, and exploration and development procedures and costs are given in Appendices D and E, including an estimate of median capital costs at about $100/kW(t) or 2.8¢ per kJ/hr capacity.

The discussion which follows reviews installed and projected types of uses. The economics of space heating are discussed in Section 6.0; and a model for the value of a very low temperature application--aquaculture--is given in Appendix H.

Table G-1 lists many applications for direct use of

- - - - - - - - - - -

Table G-1 follows

- - - - - - - - - - -

geothermal energy, ranked by the required temperature.

TABLE G-1. Temperature Ranges for Direct Use

		Temperature °F	°C	Use	
Saturated Steam		392	200		
		374	190		
		356	180	Evaporation of Highly Conc. Solutions Refrigeration by Ammonia Absorption Digestion in Paper Pulp, Kraft	Temp. Range of Conventional Power Production
		338	170	Heavy Water via Hydrog. Sulfide Proc. Drying of Diatomaceous Earth.	
		320	160	Drying of Fish Meal Drying of Timber	
		302	150	Alumina via Bayers Process	
		284	140	Drying Farm Products at High Rates. Canning of Food	
		266	130	Evaporation in Sugar Refining Extraction of Salts by Evaporation and Crystalization	
	Water	248	120	Fresh Water by Distillation. Most Multiple Effect Evaporations, Concentr. of Saline Sol	
		230	110	Refrigeration by Medium Temperatures. Drying and Curing of Light Aggreg. Cement Slabs	
		212	100	Drying of Organic Materials, Seaweed, Grass, Vegetables, etc Washing and Drying of Wool.	
		194	90	Drying of Stock Fish. Intensive De-Icing Operations.	
		176	80	Space Heating. Greenhouses by Space Heating.	
		158	70	Refrigeration by Low Temperature.	
		140	60	Animal Husbandry. Greenhouses by Combined Space and Hotbed Heating.	
		122	50	Mushroom Growing. Balneological Baths.	
		104	40	Soil Warming	
		86	30	Swimming Pools, Biodegradation, Fermentation Warm Water for Year Around Mining in Cold Climates De-Icing	
		68	20	Hatching of Fish, Fish Farming	

From (Lindal, 1974)

G.2. Elements of Economics and Conservation

Where geothermal resources can be discovered, developed and matched to a need for stationary heat, the overall system has certain characteristics:

1. Drilling and completing wells is staightforward and uses conventional water well or oil drilling rigs;
2. Development uses standard pumps, controls, pipes, etc.;
3. Development lead time is short;
4. Systems are capital intensive, but low in operating costs;
5. Pollution control measures depend on the chemistry of the geothermal fluid, and on the temperature of waste or spent fluid;
6. Annual load factors are often low;
7. A high fraction of available heat is often utilized;
8. Opportunity exists for multiple-use systems, extracting a very high fraction of available heat at progressively lower temperatures; in this sense the economics and technology are like those of systems which utilize waste heat;
9. In the broad economy, geothermal direct use systems free up fossil fuels, allowing them to be

matched to more appropriate high temperature and mobile applications; or geothermal systems permit the carrying out of an economic activity which would otherwise be non-competitive owing to high fuel costs.

G.3. Space Heating

Space heating, the most common geothermal application, has two main characteristics which distinguish it from process heating: the fluid reject temperature of space heating systems are low, and seasonal variations in the weather induce substantial fluctuations in energy demand. The latter characteristic is an important factor in the feasibility of a given system. The low rejection temperature allows the exploitation of low temperature resources and means that a greater percentage of the available energy is extracted from the thermal fluid. The minimum temperature of the fluid employed in space heating can be quite low if a heat pump is used.

The supply of geothermal energy for space heating purposes can be achieved by either of two methods. At some locations a geothermal well on site to service a single dwelling or business has proven to be technically and economically feasible. This approach is common in Klamath Falls, Oregon and is described by Lund et al (1979). One or more home owners share a geothermal well and use downhole heat exchangers to extract the energy required for space and domestic hot water heating.

A more frequently used method for exploiting and supplying geothermal energy is district heating--for a community from a central source. The community may consist of residential dwellings, offices, shops, schools, institutional buildings, commercial and industrial establishments.

District heating projects are capital intensive. Bloomster et al (1977) used a computer model to evaluate a proposed district heating project. They concluded that district heating transmission and distribution costs are basically a function of climate and community characteristics. The climate impact is determined by two factors: the minimum exterior temperature and the number of heating degree days. The minimum exterior temperature establishes the peak load and determines the size and cost of pipes. For economic reasons systems are usually not designed to meet peak demand. Peak demands are met by supplemental heat sources. The number of heating degree days establish the annual energy consumption. Where annual consumption is low, systems operate at a lower capacity factor. This leads directly to higher annual capital charges.

A study of the feasibility of geothermal applications for Riverside, California, by Fassbender, et al

(1978), recommended the use of a direct system for cooling during the summer and the provision of process heat for industrial demands as measures to overcome load factor problems.

Community characteristics can influence costs in a number of ways. A large population and subscribership helps to maximize the economies of scale for transmission and distribution. It also helps to ensure that well flows are fully utilized and thereby effects a reduction in the per capita investment in well development. Additionally, high population density decreases costs by reducing the average length of the distribution pipe run.

The proximity of the load to the geothermal fluid is important. Pipelines more than 5-10 kilometers are generally not economic for two reasons: capital cost and heat loss in transit. However, in Iceland the heating needs of a town of 12 000 are serviced by a 20 KM pipeline (Lund, 1978), and transmission distances of 50 and 100 KM are being discussed.

G.4. Characteristics of Process Heating

Industrial process heating is an attractive candidate for near-term penetration of geothermal resources. Processes requiring temperatures in the fossil fuel flame range preclude geothermal heat; however, the industrial processes which require lower temperatures are numerous. One U.S. study estimates that process steam and direct process heat within geothermal temperature ranges account for 68.4 percent of total industrial energy demand (Peterson, 1979). Nearly 8 percent of process heat is needed at terminal process temperatures below 100°C. If conventional preheating is used, the proportion of the total process heat lying below 100°C exceeds 8 percent.

If the temperature of the resource and the process are compatible, and the process is energy intensive, there is a strong probability that geothermal resources are economical. Although transmission and distribution costs are important considerations, many industries have relatively high and constant load factors and demand is localized. These characteristics match efficient capital employment in geothermal resources.

Capital costs for industrial applications in contrast to residential heating, can be reduced by designing the fluid transmission system to meet base rather than peak energy demands. Conventional fuels can be used for peaking, or heat can be stored during off peak periods.

Where retrofitting is necessary, the costs incurred by the individual industrial establishment depend largely on the kind of heat radiating equipment in place. In many plants water is the main heat carrying medium. In those cases retrofitting costs are likely to be low. If the geothermal fluid is corrosive or some danger of contamination exists, the installation of a water-water heat exchanger will be the major cost. Where air is the heat carrying medium, more expensive retrofitting may be necessary.

G.5. Examples of Projects, Systems, and Studies

Until recently, the only Canadian experience with non-electrical applications of geothermal energy was limited to the use of water in or piped from hot springs at resorts in B.C., Alberta, and the Yukon Territory, and one low-temperature (15°C) well at Mayo, Y.T.

A pioneering effort to capture geothermal energy was initiated at the University of Regina during December 1978 (Vigrass, 1979). The objective of the Regina project is to utilize sedimentary-basin resources for space heating on the campus. The researchers have found water at about 65°C. The cost of drilling the producing well was about $700 000. The complete geothermal heating system is expected to cost $1 500 000. After flowing through a water/air heat exchanger the geothermal brine will be reinjected into a disposal well (see also pages C-19 and C-20).

Whereas Canadian experience with geothermal applications is very limited, a considerable amount is known from conventionally fueled systems. District heating systems, for example, operate in Vancouver, Winnipeg and Toronto to heat large commercial buildings. The total heat consumed by customers is 767 000 MWh(thermal)/year or 2.76 x 10^6 GJ/year. Approximately half of the consumption is accounted for by Toronto's 69 customers.

The existing systems use steam at pressures of 480, 860, and 1 400 kPa as the heat carrying medium. Experience in Europe indicates that the use of hot water as the heating fluid is safer and the infrastructure is less costly to construct and operate. Projects being considered for Edmonton, Winnipeg, Ottawa, Halifax, and the Ontario "new towns", North Pickering and Townsend, will likely be based on the low pressure European model (J. F. Maclaren Ltd., 1978). With the price of fossil fuels rising, researchers at a number of Canadian locations have shown interest in recovering the large volumes of waste heat produced by electrical generating stations and similar installations. The feasibility studies and experimental projects which have been undertaken have tended to emphasize agricultural applications--greenhouse heating and fish farms.

Conestoga-Rover & Associates (1977) studied the feasibility of utilizing heat from the Bruce Nuclear Power

Development for agricultural and aquacultural purposes. The study was based on the assumption that the cooling water would be discharged from the condensor at a rate of 220 000 liters per minute and a winter-time temperature of 40.5°C. The findings of the study showed that both proposed applications of the waste heat were technically feasible.

In Alberta, two projects involving the recovery of waste heat for greenhouse heating have been undertaken the past five years. At Calgary Power's Lake Wabamum thermal generating plant (located at 58° N latitude) a Filacell mass transfer system--a highly efficient direct contact water to air heat exchanger--was evaluated for its ability to recover low grade heat (Shaw et al ca. 1976). The researchers concluded that to provide minimum night temperatures in the 15-21°C range, the minimum supply water temperature must be 21-17°C.

At Princess, Alberta* a commercial scale greenhouse project (4 000 m^2) was the first such facility in Canada to utilize waste heat generated by the exhaust gases of a natural gas compressor station. Climate design parameters for the site were -35°C and 5 350 degree days below 18°C. The calculated heat load of the structure was 1 230 kW(t). The waste heat boiler was a shell and tube heat exchanger with the exhaust gases on the tube side. A 50-50 glychol-water mixture was used as the heat transport medium. The glychol-water mixture was heated to 93°C and then flowed through a liquid-air heat exchanger which transferred the heat energy to the greenhouse air. Tomatoes and cauliflower were produced in the facility.

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*Subsequent to start up, an explosion and fire at Princess destroyed the greenhouse facility.

Much of the available information regarding applications of geothermal energy and other forms of low grade heat is based on research undertaken in the U.S., Iceland and New Zealand.

A study by Kim et al (1979) prepared for the U.S. House of Representatives identified the following industries as the major users of process heat at temperatures below 54°C: food processing, textiles, furniture, pulp and paper, chemicals, concrete block manufactures, iron and steel foundries, and automobile manufacture. In the temperature range up to 54°C, the food processing industry appears to be the best market. In the temperature range up to 82°C possible markets include food processing, concrete block manufacture, automobile manufacture, and iron and steel foundries. Space and domestic hot water applications were considered to be economically feasible when employed in district heating systems.

Research related to agricultural and food processing applications of geothermal energy has been conducted by numerous individuals and agencies. Vorum et al (1978) studied sugar beet refining and barley malting. They found that geothermal brines of 104°C and higher could provide 100 percent of the energy required for barley malting and were competitive with fossil fuels. A short operating season detracted from the economics of sugar beet refining.

Lienau et al (1978) examined the engineering and economic feasibility of employing low grade geothermal resources for alfalfa drying and heating tree seedling greenhouses. The alfalfa drying facility is a forced air multilayer conveyor belt modeled on one operated at Broadlands, New Zealand, since 1973. It requires geothermal fluid temperatures of 121°C-135°C. The economic analysis compared the geothermal plant with the oil-fired rotary flame furnace normally used in the U.S. Although capital costs for the geothermal system were 60 times higher than for the conventional system, profit margins from the geothermal system project at double those for the oil system.

Their model of the seedling greenhouse assumed a fluid temperature of 93°C. Annual non-fuel operating and maintenance costs for the geothermal greenhouse were found to exceed those for a natural gas heated facility because of the need for well and pump maintenance. A saving in fuel costs, however, resulted in overall annual costs of approximately 30 percent of those for the conventional system.

Harris et al (1977) discussed geothermal absorption refrigeration for good processing industries. A refrigeration design temperature of -40°C can be achieved using the thermal fluids of 150°C flowing at 44 L/S. The fact that (in the U.S.) energy costs constitute only 1 percent of the products' retail prices is identified as one of the major factors forestalling the adoption of alternative energy sources by the food processing industry.

The report contains a study of the economics of geothermal space heating as Section 6.0. A number of other recent studies of district space heating, some of specific projects, have been done in the U.S.

Lund et al (1979) provide an economic evaluation of a 3-phase district heating scheme proposed for Klamath Falls, Oregon. Initially the plan is to provide heating fluid to 14 government buildings. Ultimately a 54-block area of the city is to be serviced. A central heat exchange facility will utilize thermal fluid at 104°C to heat fresh water in a closed loop distribution pipeline to 93°C. A flow rate of 425 L/S will be required. Waste water will be reinjected into the ground.

Zastlaka (1979) describes a proposal to heat several buildings in the Boise, Idaho, Capital Mall. The wellhead temperature of the fluid used in the system is 77°C. Waste water will be discharged into the Snake River.

Engen (1978) compares the cost of geothermal and conventional systems of residential space heating. For the purposes of the analysis a design temperature difference of 21°C and 6 000 annual degree days are assumed. The study suggests that hot water convection systems are the most economical, with minimum thermal fluid temperatures of 66°C desirable.

Geothermal forced air space heating is probably the most desirable type of residential heating system because of the general acceptance of forced air systems and the ease of adapting them to include additional features such as cooling, air filtration and humidity control. Geothermal forced air systems can use water at temperatures as low as 49°C. Engen concluded that the cost of geothermal energy for a forced air system may range up to 90-95 percent of the cost of electricity or natural gas and remain cost competitive with the corresponding conventional system.

G.6. Possible Direct Geothermal Uses in British Columbia

In British Columbia approximately 47 percent of all energy consumed is utilized for space or process heating.

This figure suggests that there are an abundance of opportunities within the Province to employ geothermal energy in some non-electrical capacity.

The comments in this section are based on our concepts of where geothermal resources are likely to be found (see Drawing 3-7), and some observations on the geography and industrial fabric of British Columbia. Until such time as resources are proven, the discussion is speculative.

Communities which lie in or near prospective geothermal resources are listed in Table 6-18, in Section 6.0., the discussion of space heating economics. The 50 communities listed range in size from regional and industrial centres--Prince Rupert, Terrace, Kelowna, Chilliwack, Cranbrook, etc.--to the very small crossroads--Likely, Liard Crossing, etc.

Table G-2 summarizes consumption of fuel and electricity in terms of monetary value, by the various manufacturing sectors in the Province. Although monetary value does not necessarily reflect energy content, they are assumed to be an index of such.

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Table G-2 follows

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The forestry sector, specifically the pulp and paper manufacture, is a large user of energy and process

TABLE G-2. B. C. Manufacturing Industries - Value of Shipments and Consumption of Fuel and Electricity

	Value of Shipments	Cost of Fuel and Electricity	Energy Costs as % of Value of Shipments
	$'000		%
Food and Beverage	1,749,106	15,603	.9
Rubber and Plastic Products	63,450	864	1.4
Textile Industries	32,167	239	.7
Clothing Industries	65,501	224	.3
Wood Industries	3,321,248	65,895	1.9
Furniture and Fixtures	63,388	406	.64
Paper and Allied Industries	1,898,461	137,140	7.2
Printing, Publishing and Allied Industries	250,880	1,475	.58
Primary Metals	569,857	9,812	1.7
Metal Fabricating	496,693	4,527	.9
Machinery	237,763	1,972	.82
Transportation Equipment	441,074	2,069	.46
Electrical Products	114,865	740	.64
Non-metallic Mineral Products	244,197	19,546	8.0
Petroleum and Coal Products	759,438	9,691	1.3
Chemical and Chemical Products	321,466	17,391	5.4
Miscellaneous	71,321	352	.5
Total	10,719,059	288,004	2.7

SOURCE: Statistics Canada, Cat. 31-203, 1977.

heat in B.C. The industry already generates an estimated 64 percent of the total energy it consumes from waste pulping liquors and hog fuel. Self-sufficiency is forecast to increase to 73 percent by 1992; for some new mills 85 percent self-sufficiency is considered to be possible (B.C. Energy Commission, 1978).

In the lumber industry much of the energy used is for motive power; process heat generated with fossil fuels is used primarily for kiln drying lumber. Conventional kiln dryers operate at temperatures below 100°C (Bramhall and Wellwood, 1976), within the range of some geothermal fluids. B.C. sawmills, like pulp mills, are rapidly opting for self-sufficiency by replacing fossil fuel burners with burners designed to be fueled with wood residues.

We feel that geothermal energy is likely to be used in the forest, wood and paper sector only under unusual circumstances, because of the availability of combustible waste.

In terms of the value of the energy consumed as a percentage of the total value of their shipments, other energy intensive industrial groups in B.C. include nonmetallic mineral products, chemical and chemical products, primary metals, rubber and plastic products, and petroleum and coal products.

The non-metallic minerals sector is dominated by cement manufacturers. While the cement industry requires large quantities of process heat, the high temperatures necessary preclude geothermal application. Redi-mix concrete producers utilize some process heat, however, the value of the energy consumed amounts to less than 15 percent of the total value of their shipments.

In most of the other industries listed above, the process heat is utilized at temperatures beyond the range of geothermal fluids; if lower temperatures are required, the waste heat already generated in the plant can be cascaded for lower temperature applications.

The most suitable candidates for geothermal conversion in B.C.'s manufacturing sector are in the food and beverage group. Specific industries best matched to geothermal energy include distilling, brewing, and fruit and vegetable processing. All three can satisfy their process heat requirements with fluids in 116°C range. The fruit and vegetable industry could also utilize geothermal energy to power absorption refrigeration units. Energy costs, however, represent a relatively minor portion of these industries' total production costs.

Moreover, food processing plants consume a large percentage of their annual demand during the several summer and fall months in which canning or freezing activities peak. The large annual fluctuation in energy demand results in the inefficient use of capital, the cost of which constitutes the largest component of the annual cost of producing geothermal energy.

Most plants in the above industries are located with reference to other factors beside cost of thermal energy. Some are highly resistant to relocation. As with communities, we expect that future utilization of direct geothermal energy will be determined by proximity and characteristics of the proven resource.

One of the strongest and most appropriate agricultural uses is greenhouse heating. Greenhouse crop production is energy intensive. The resource temperatures required are relatively low and geothermal energy is compatible with greenhouse heat exchange hardware. If the appropriate crops are grown locational factors need not be a drawback.

The economic incentives to convert to alternative energy sources for greenhouse heating are powerful. Currently natural gas and fuel oil are used to heat greenhouses in B.C. A study of greenhouse cucumbers and tomatoes shows that during 1978 fuel costs accounted for approximately 20 percent of total annual operating costs (B.C. Ministry of Agriculture).

Where greenhouse products are delivered to the urban market the location of the operation can be an important factor in its economics. As the cost of conventional fuels rises relative to geothermal energy costs, the disadvantage arising from the site-specific nature of geothermal energy diminishes.

The impacts of location can also be minimized by growing a non-market crop. Tree seedlings are incubated in the U.S. Given the renewed vigor with which forest management is to be pursued in the coming years, establishing a geothermally heated seedling greenhouse could prove to be a very timely venture.

Trout and salmon culture is also ideally matched to geothermal energy, and an economic model is given in Appendix H.

APPENDIX H. ECONOMIC MODEL FOR AQUACULTURE

H. Economic Model For Aquaculture*

H.1. Introduction

The "Salmonid Enhancement Program " (SEP) is a major ambition of the federal government in B.C. Private aquaculture is being encouraged by the provincial government. Since geothermal energy and aquaculture are ideally matched, the physical and economic parameters are reviewed here.

Aquaculture is widely practiced throughout the world for production of food fish. Species produced include shellfish low on the food chain, such as oysters and prawns; fish such as catfish, carp, and tilipia; and higher fish such as the salmonids: salmon and trout.

A fresh water Malaysian prawn (Macrobrachium rosenbergii) has been recently adapted and is grown principally in Asia, Hawaii, and southern U.S.

Oysters are being cultured in British Columbia, in natural tidal waters--a passive process that consists of enhancing the natural habitat and maintaining and harvesting the crop. Trout are being reared in active systems, that is hatcheries where the trout are fed, and where water conditions are closely monitored and controlled, mainly in the Fraser Valley. "Pot hole" trout farming, a passive rearing method, is not widely practiced in B.C.

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*This appendix was prepared in 1980 from information supplied by Indian Arm Salmon Ltd. which has been involved in aquaculture since 1974. That company was affiliated with Nevin Sadlier-Brown Goodbrand Ltd., and was merged into NSBG in 1981.

Salmon, particularly coho, are currently being grown in British Columbia by four producers in the private sector and by some Indian bands.

H.2. Geothermal Aquaculture

The marriage of geothermal energy and aquaculture has been discussed in several quarters and has been successfully executed on pilot and production scales locally in various places outside British Columbia.

In Japan, some operators raise lower order fish, eels, and alligators with the use of geothermal fluids. Malaysian prawns have been raised at Oregon Institute of Technology in geothermal water in a pilot program (OSU, 1978) and a private operator is currently installing a production-scale plant in the Imperial Valley, California (Grajcer, 1979). A private operator at Twin Falls, Idaho has raised and sold at least one production lot of catfish in 32°C geothermal water (PIC, 1979, p. 70). The Idaho National Engineering Laboratory has conducted a pilot rearing of carp and catfish in undiluted Raft River geothermal well water (Sullivan and Beleau, 1979).

Independent farmers in Iceland have raised Atlantic salmon for years using geothermally heated or supplemented waters, principally as game fish for wealthy European anglers. State governmental authorities in Alaska have discussed site-selection criteria for salmon hatcheries in coastal Alaska, using some of the abundance of hot spring waters which exist there. The major trout farming centre in Buhl, Idaho, makes use of a widespread spring system at a constant 14°C--a low-grade geothermal resource. Goodbrand and Crandall (1979) made a preliminary assessment of hot springs in the Pacific drainage of British Columbia for potential salmon hatchery applications for Fisheries Canada.

H.3. Model System for Salmon and Trout

Two salmonid hatchery models, using geothermal energy, are summarized in Table H-1. The first model raises coho or chinook salmon to smolt size for seasonal release. This is the conventional government hatchery intended to enhance the commercial and sport fishery. Water demand for such a hatchery is directly related to the annual production, in this case 1 000 L/s for annual smolt production of about 35 000 kg.

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Table H-1 follows

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The second hatchery is a rainbow trout farm which produces about 2 600 000 pan-sized fish for the wholesale fish trade on a level year-round production schedule.

TABLE H-1. General Parameters for Model Salmonid Hatchery and Rearing Facilities using Geothermal Energy

Type Facility:	Coho or chinook rearing to smolt size and release; flow-through hatchery	Rainbow trout farm, to market size; 90 percent recirculating raceways
Capacity:	1 500 000-25 gram coho or 7 000 000-5 gram chinook per year; total about 35 000 kg/yr	1 600 000-340 gram trout; 900 000 kg total/year
Surface Water:	Demand 1 000 litres/second; river water temperature ranges from 3°C in winter to 10°C in summer	Demand 500 litres/second; stream water temperature ranges from 1°C in winter to 14°C in summer
Heat Needed:	To heat to 10°C year-round, peak demand is 29 000 kWt; yearly average demand is 15 000 kWt; annual energy consumption is 130 000 000 kWh(t) or 470 000 000 000 kilojoules	To heat to 14°C year-round, peak demand is 27 000 kWt; yearly demand is 14 000 kWt; annual energy consumption is 120 000 000 kWh(t) or 430 000 000 000 kilojoules

Demand for fresh water is similarly related to the standing crop at any given time, and in this instance is about 500 L/s. A recirculating system is used, which treats and recycles 90% of the intake water, in order to conserve thermal energy.

The relationship between temperature and salmonid growth is well established for each species. In the incubation stage salmon and trout can survive in water which is near freezing, but the population grows faster and is generally healthier if water is 5°C or warmer. An ideal temperature for salmon smolt rearing might be 10°C; that for trout might be 14°C year-round. At temperatures of 18°C or more, the dissolved oxygen content of the water decreases to the extent that prolonged exposure is lethal.

For purposes of release, the higher temperatures of 10°C produce larger and more vital smolts than low temperatures. For purposes of marketing a crop of pan-sized fish, the higher water temperatures, particularly around 14°C, result in fish that grow to market size in 10-14 months. Market size takes as much as 22 months at low temperatures. Rapid growth is a considerable benefit to the fish farmer in the reduction of fixed costs, the reduction in inventory carrying costs, the conversion ratio of feed to weight, and the drop in time-dependent mortalities.

Each model includes a river or stream water temperature characteristic of southern B.C. Each model assumes that the hatchery manager desires to heat the surface water to the optimum operating temperature year-round. In each case the peak heat demand approaches 108 000 000 kJ/h or 30 000 kW(thermal), and the yearly average demand approaches 50 000 000 kJ/h or 15 000 kWt. The operator who wished to supply all heat geothermally would need about six good wells for peaking thermal demand (see Appendix E).

The most economical method of capturing the heat would be to directly mix geothermal and surface waters. If the geothermal waters contain deleterious constituents, such as copper, zinc, or hydrogen sulfide, a heat exchanger would be required.

H.4. Economics

In government hatcheries operated for smolt release, water is periodically heated with fossil fuels. The cost of fuel is an important factor; however, the benefits are deemed worth the expense. Operating economic constraints are not as severe for them as for the private operator.

For the private operator higher temperatures are important; however, the cost of heating large volumes of water even a few degrees with fossil fuel is prohibitive, except when absolutely necessary for crop survival.

As an example, during the years 1974 through 1978 one private operator periodically heated 2.3 liters/second enough to raise water temperature 2°C. This amounts to a heating load of about 72 000 kJ/h or 20 kWt. The cost of doing this with stove oil was about $750 per month, or 53 mils per kWt. Stove oil prices have more than doubled since that undertaking, so the present price might exceed 100 mils per kWt. If these figures were projected to the model trout farm in Table H-1, the cost of heating year-round to 14°C would be about $12 000 000. The operator's production would sell for about $4.20 per kilogram wholesale, or a total of about $4 000 000. It is clearly not cost efficient to use stove oil in trout farming operations for total heating.

The growth of trout to market size generally takes about 18 to 22 months in natural water which varies seasonally from 1°C to 14°C. In water of a uniform 14°C temperature the same growth takes about 10 to 14 months. One operator interviewed said that he would value the advantage of the required heat at about 45¢ per kilogram of fish produced. For the model trout farm described this would be about $400 000 per year, or about 3.3 mills per kilowatt hour (thermal). Assuming negligible operating costs for the geothermal system, the trout farmer would be willing to retire the capital cost of geothermal wells and installations over a period of time at the rate of

$400 000 per year. At a discount rate of 12%, using an amortization period of 15 years, an operator would be willing to spend about $2 700 000 for low-risk development of this energy source. When this capital cost is set against capacity, the farmer would consider paying $90.00/kWt.

APPENDIX I. LEGAL CONSIDERATIONS

I. LEGAL CONSIDERATIONS

I.1 B.C. Geothermal Resources Act (1982). The Geothermal Resources Act defines the goethermal resources and specifies the conditions for exploration and development. It is the primary legislation governing geothermal resources although many aspects are left to regulations as yet undeveloped. The act is reproduced in full in the following pages:

GEOTHERMAL RESOURCES ACT

CHAPTER 14

[Act administered by the Ministry of Energy, Mines and Petroleum Resources]

Assented to June 7, 1982.

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PART 1

INTERPRETATION

Interpretation

1. (1) In this Act

"block" has the same meaning as in section 140 (3) of the *Petroleum and Natural Gas Act;*

"boundary" means a location's surface boundary and its vertical extension;

"commissioner" means the commissioner of the titles branch of the Petroleum Resources Division of the ministry;

"development plan" means a plan for the drilling of such number of wells as are, in the opinion of the minister, sufficient to enable production of a geothermal resource underlying a lease to begin, including the provision of piping, equipment, reinjection wells and controls required to produce the geothermal resource, but does not include plans for the commercial utilization of the geothermal resource or for converting it into any other form of energy;

"division" means the Petroleum Resources Division of the ministry;

"division head" means the assistant deputy minister designated in writing by the minister as having charge of the division;

"field" means

(a) the surface of land that is underlaid or appears to be underlaid by a geothermal resource, and

(b) the subsurface region vertically beneath that land surface

that is designated by the division head as a field;

"geothermal exploration" means investigation of the subsurface of land for the presence of a geothermal resource by means of

(a) seismic, gravimetric, magnetic, radiometric, electric, geological or geochemical operations,

(b) well drilling or test hole drilling, or

(c) any other method approved by the division head;

"geothermal resource" means the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well, but does not include

(a) water that has a temperature less than 80°C at the point where it reaches the surface, or

(b) hydrocarbons;

"geothermal rig licence" means a geothermal rig licence issued under section 12;

"geothermal well" means a well in which casing is run and that the minister considers is producing or capable of producing a geothermal resource from a geothermal resource bearing zone;

"holder of a location" means, in accordance with the context, a permittee or lessee;

"interest" means an undivided interest in a location;

"lease" means a disposition under section 8 of the right to produce, subject to this Act, a geothermal resource from a location;

"lessee" means a person in whose name a lease is recorded in the division records;

"location" means the area described in, and in respect of which rights are given by, a permit or lease;

"ministry" means the ministry of that minister charged by order of the Lieutenant Governor in Council with the administration of this Act;

"officer of the division" means a person employed in the division and authorized by the division head to give an approval under this Act;

"permit" means a permit issued under section 5;

"permittee" means the person in whose name a permit is recorded in the division records;

"produce" means extract or obtain from the earth;

"production plan" means a plan approved under section 4 (1);

"test hole" means a hole drilled or being drilled

(a) with a bore hole diameter of 100 mm or less, or

(b) to a depth not exceeding 600 m,

to obtain information about a geothermal resource, but does not include a hole drilled or being drilled for firing an explosive charge in seismic operations;

"unit" has the same meaning as in the *Petroleum and Natural Gas Act;*

"unitized operation" means the development or production of geothermal resources or the implementing of a program for the conservation of geothermal resources or the coordinated management of interests in them in, on or under a location, part of a location or a number of locations combined for that purpose under a unitization agreement under this Act;

"well" means a hole or shaft that is or is being drilled, bored or otherwise sunk into the earth

(a) through which a geothermal resource is or can be produced,

(b) for the purpose of producing a geothermal resource or for the purpose of injecting any substance to assist the production of a geothermal resource, or

(c) that

(i) extends deeper than 600 m,

(ii) has a bore hole diameter of more than 100 mm, and

(iii) is intended to obtain information about a geothermal resource.

(2) Sections 6 to 31 of the *Petroleum and Natural Gas Act* apply in respect of entry onto and use of land for the purpose of exploring for and producing geothermal resources.

(3) For the purpose of subsection (2), "produce" and "producing" in sections 7 to 11 and 16 of the *Petroleum and Natural Gas Act* have the same meaning as in this Act.

(4) Where there is inconsistency between a provision of the *Utilities Commission Act* or *Water Act* and a provision of this Act, the provision of the *Utilities Commission Act* or *Water Act* prevails.

1982-14-1.

PART 2

OWNERSHIP OF GEOTHERMAL RESOURCES AND GENERAL PROHIBITIONS

Geothermal resources vested in the government

2. The right, title and interest in all geothermal resources in the Province are vested in and reserved to the government and the government may dispose of them only under this Act.

1982-14-2.

Dispositions approved by Lieutenant Governor in Council

3. The minister may, notwithstanding Part 3, dispose of geothermal resources on terms approved by the Lieutenant Governor in Council.

1982-14-3.

Prohibitions

4. (1) No person shall produce a geothermal resource other than for testing purposes unless

(a) he does so in accordance with a plan for the production of the geothermal resources underlying the location of a lease,

(b) the plan is approved, with respect to matters of energy conservation and operational safety, by the minister, and

(c) he is the lessee of the location where the well that produces the geothermal resource is situated.

(2) No person shall drill or operate a well except within the boundaries of a location.

(3) No person shall drill a test hole unless a test hole program authorization has been issued for the test hole.

(4) No person shall drill or operate a well unless a well authorization has been issued for the well.

(5) No person shall, for the purpose of exploring for or producing a geothermal resource, operate a drilling rig or service rig except in accordance with a geothermal rig licence issued for the rig under this Act or a rig licence issued for the rig under the *Petroleum and Natural Gas Act*.

(6) No person shall conduct geothermal exploration other than by way of well drilling or test hole drilling unless he has notified the commissioner in writing in the form prescribed of his intention to do so.

1982-14-4.

PART 3

PERMITS AND LEASES

Permits

5. (1) The minister may issue or refuse to issue a permit, whether or not the requirements of this Act have been complied with, and his refusal is final.

(2) A permit shall define the boundaries of a location.

(3) A permittee shall pay a prescribed rent for the permit.

(4) A permittee has the exclusive right, subject to section 13 (2) and the regulations, to apply for well authorizations for wells to be drilled within the boundaries of his location.

(5) The minister shall not issue a permit

(a) except by public tender, and

(b) unless, at least 2 weeks before the day the permit is issued, a notice stating the terms on which the permit is available for disposition has been published in the Gazette.

(6) Where the minister refuses to issue a permit, any fee and rent that accompanied the application shall be refunded to the applicant out of the consolidated revenue fund.

(7) A permit expires on the first anniversary of the date of its issue or of its most recent renewal.

(8) Application for renewal of a permit shall be made to the commissioner who may, subject to the regulations, renew it.

(9) A permit shall not be renewed more than 7 times except on the written authorization of the minister and subject to the rents, terms and conditions he imposes.

(10) The minister may, when acting under subsection (9), authorize a renewal for a period of less than one year.

1982-14-5.

Permit: dimensions of location

6. (1) The maximum size of a location for which a permit may be issued is a block.

(2) The boundaries of a location comprised in a permit shall coincide with the boundaries of units unless the location is in an area provided for in subsection (3).

(3) In any area where the boundaries of units and blocks do not coincide with surveyed boundaries of sections, townships or another district lot system, the boundaries of a location comprised in a permit may, notwithstanding anything in this Act, be established to coincide with the surveyed boundaries of a section, a township or other district lot system.

1982-14-6.

Work requirements

7. (1) A permittee shall, each year in accordance with the regulations,

(a) carry out in respect of his location geothermal exploration of a prescribed value, or

(b) make payments in lieu of the work.

(2) A permittee shall record all work, including road construction giving access to the location, with the commissioner in the permit year in which it is done.

1982-14-7.

Leases

8. (1) Where a geothermal well has been drilled on a location and the permittee submits a development plan for the location that the minister considers satisfactory, the minister may, in accordance with the regulations and on terms and conditions he considers desirable, issue a lease in respect of the whole or any part of the location.

(2) The minister shall not issue a lease except to a person who holds a permit that includes the location of the lease, and when the lease is issued the permit expires with respect to the location of the lease.

(3) A lessee shall pay a prescribed rent for the lease.

(4) A lease expires on the 20th anniversary of the commencement of its term, and where renewed, expires

(a) on the 5th anniversary of its renewal, or

(b) where a production plan for its location has been approved, on the 20th anniversary of its renewal.

(5) Section 6 applies in respect of the issue of a lease.

(6) Subject to subsection (7), where the minister is satisfied that a lessee is not in default of any of his obligations under this Act or under the lease, he shall, on application

by the lessee made within 90 days before the expiry of the lease, issue to the lessee a renewal of the lease.

(7) The minister may, where part of the location of the lease is the subject of

(a) a production plan,
(b) an agreement respecting royalty under section 17, or
(c) a unitization agreement under section 18,

confine the renewal of the lease to that part of the lease location.

1982-14-8.

Transfers and assignments

9. (1) The commissioner shall maintain a register in which shall be recorded transfers and other instruments affecting the title to permits and leases.

(2) A transfer or other instrument shall not be registered unless it complies with the regulations.

(3) On registration, a transfer or other instrument affecting the title to a permit or lease shall be deemed to be registered and be effective from the time that the commissioner receives the application to register it.

(4) Failure to register a transfer or other instrument affecting the title to a permit or lease does not invalidate it as between the parties to it, but subsection (3) governs its effectiveness for any other person.

(5) A holder of a permit or lease may transfer his permit or lease directly to himself jointly with another person, and where the permit or lease is held by more than one person, they may transfer it directly to one or more of their number either alone or jointly with another person, and a trustee or personal representative may transfer a permit or lease to himself individually where the making of the transfer is otherwise within his power.

1982-14-9.

Cancellation

10. Where a permittee or lessee fails to comply with

(a) a provision of this Act or the regulations,
(b) a notice or an order under this Act or the regulations, or
(c) a term, covenant or condition of his permit or lease,

the minister may give him notice to comply, and if the holder fails to comply within 60 days after the date the notice is received by him, the minister may, in writing, declare the permit or lease to be cancelled, and at the end of the day specified in the minister's declaration, the permit or lease terminates.

1982-14-10.

Default in rent

11. Notwithstanding anything in this Act, where a lessee fails to pay the rent payable under his lease, the lease expires on the 60th day after the date the rent was payable unless before the 60 days have elapsed he pays

(a) the rent, and
(b) for each 30 day period or part of it that he is in default a sum equal to 2% of the yearly rent.

1982-14-11

PART 4

OPERATION AND CONSERVATION

Authorizations and licences

12. (1) Subject to the regulations, the division head or a person authorized by him in writing to do so may issue, subject to conditions, restrictions and stipulations he considers necessary or desirable, or may refuse to issue, a test hole program authorization, well authorization or geothermal rig licence.

(2) A geothermal rig licence expires one year from its date of issue.

(3) A person to whom a test hole program authorization or well authorization is issued (an "operator") shall deposit with the minister

(a) cash,
(b) Government of Canada and Provincial direct or guaranteed securities having a maturity of not longer than 3 years, or
(c) chartered banks', trust companies' or credit unions' certificates of deposit where supported by an appropriate letter giving direction concerning payment of the funds to the Minister of Finance,

in an amount prescribed by the regulations as security for the proper completion of the well or test hole in compliance with the Act and regulations.

(4) When the application for a well authorization or a test hole program authorization is not approved, the deposit shall be returned to the applicant in accordance with any directive of the Minister of Finance under section 19 (3) of the *Financial Administration Act*.

(5) The deposit or part of it may be refunded to the operator on completion of the drilling of the test hole or well in accordance with the Act and regulations to the satisfaction of an officer of the division.

1982-14-12.

Limitations on issue

13. (1) No well authorization shall be issued except to

(a) a permittee or lessee, or
(b) a person who has made an agreement with a permittee or lessee for the drilling or operation of the well.

(2) A person referred to in subsection (1) (b) may apply for a well authorization.

1982-14-13.

Access and inspection

14. (1) At any reasonable time, persons authorized in writing by the division head have the right, with respect to a geothermal resource,

(a) to enter on and inspect any well or place at which geothermal resources are handled, processed or treated, and any place used or occupied for those purposes,
(b) to inspect all equipment, plant and records relating to the resource, and
(c) to take samples or particulars or carry out tests or examinations.

(2) Where records required by the regulations to be kept are kept at a place other than a place referred to in subsection (1) (a), persons employed in the division and authorized in writing by the division head have the right, during normal business hours

and after giving reasonable notice to the persons affected, to inspect the records, and for that purpose to enter the place where the records are kept.

(3) A person authorized by the division head to exercise any of the powers in subsection (1) or (2) shall produce on demand his authorization signed by the division head and his identification card signed by the minister.

1982-14-14.

Removal of equipment

15. A person who has failed to comply with

(a) this Act or the regulations,
(b) a notice given or order made under this Act or the regulations, or
(c) a term, covenant or condition of his permit or lease,

shall not remove or allow to be removed equipment from a location or former location without permission in writing from the commissioner.

1982-14-15.

Health and safety

16. (1) A person holding a permit or lease shall keep all machinery, equipment, test holes, wells and other facilities on the location in a safe condition.

(2) The duty imposed by subsection (1) continues after the expiry or other termination of the lease or permit, until an officer of the division issues a certificate of restoration certifying that

(a) all equipment, machinery, test holes, wells and other facilities on the location of the lease or permit have been removed, plugged or are otherwise in safe condition in accordance with prescribed standards, and
(b) the land surface of the location has been restored to a satisfactory condition in accordance with the regulations.

(3) The minister may refuse to accept a surrender of a permit or lease where an officer of the division has not issued a certificate of restoration.

(4) Where an officer of the division, after inspection of a location or well, considers that a method or practice being employed in connection with the location or well constitutes or may constitute a hazard to the health or safety of any person, or of the public, he may give notice of it in writing to the permittee or lessee of the location, or to the holder of a well authorization or test hole program authorization for the well, or to the agent or representative of any of them, setting out the remedial measures the officer requires be taken.

(5) Where the officer of the division considers that delay in implementation of the remedial measures would constitute a danger to any person or to the public, he may in the same notice or subsequently order in writing that

(a) the method or practice be discontinued, or
(b) all operations in the location or in connection with the well cease

until the matter is remedied to the officer's satisfaction.

(6) No person, knowing that an order has been made under subsection (5), shall continue a method, practice or operation contrary to the order.

1982-14-16.

PART 5

ROYALTY AND UNITIZATION

Royalty

17. (1) Every lessee who produces a geothermal resource for purposes other than testing shall pay to the government

(a) a royalty established by agreement under this section,
(b) an amount agreed under this section to be paid instead of royalty, or
(c) where no royalty or amount has been agreed under this section, the prescribed royalty.

(2) The minister may enter into an agreement approved by the Lieutenant Governor in Council

(a) establishing the rate of royalty and the method of calculating it, or
(b) by which the government receives, instead of royalty, a share of the income revenue or profit generated from the production of a geothermal resource.

(3) A lessee who fails to pay when it is due a royalty or an amount agreed to be paid instead of royalty shall pay interest on the unpaid amount at the prescribed rate calculated from the time the unpaid amount becomes due until payment is made.

1982-14-17.

Unitization agreement

18. (1) The minister may on behalf of the government enter into a unitization agreement for the unitized operation of a field or a part of it.

(2) Section 9 does not apply to an agreement entered into under this section.

1982-14-18.

Unitization order

19. (1) On receipt of an application for a unitization order from a lessee or group of lessees who hold locations that comprise at least 2/3 of the area proposed to be operated under the unitization agreement and who have agreed in writing to a proposed unitized operation, the minister may invite interested persons to make, within a time he specifies, submissions respecting the advisability of or necessity for a unitization agreement.

(2) After reviewing the submissions or on expiry of the time specified by him under subsection (1), the minister may reject the application or make a unitization order requiring that the plan of unitized operations proposed by the applicant be applicable to the whole of the proposed unitized area, or to any area situated in the same field that he determines, and the order is binding on all owners of interests in the area ordered by the minister to be subject to the plan of unitized operations.

1982-14-19.

PART 6

GENERAL

Inspection and confidentiality

20. (1) The register maintained under section 9 (1) shall be open to public inspection during normal office hours.

(2) Where the ministry receives

(a) a geothermal exploration report, or

(b) records or data respecting a well,

the report, records or data shall not be disclosed to any person except as authorized by the regulations.

1982-14-20.

Affidavits

21. An affidavit required under the regulations may be made before

(a) a person authorized under the *Evidence Act*, or

(b) the commissioner.

1982-14-21.

Offence and penalty

22. (1) A person commits an offence who contravenes section 4, 15 or 16 (6) or any regulation creating an offence.

(2) A person who commits an offence is liable on conviction to a fine of not less than $500 or not more than $5 000.

(3) Section 5 of the *Offence Act* does not apply to

(a) this Act, or

(b) the regulations.

1982-14-22.

Regulations made by minister

23. (1) The minister may make regulations of general application or related to a specific location or well governing the drilling of wells and test holes and the production and conservation of geothermal resources including regulations for the following purposes and regulations respecting the following matters:

(a) prohibiting the drilling of a well at any place within a prescribed distance of any boundary, roadway, road allowance, right of way, building of any specified type or any specified work;

(b) requiring permittees and lessees to submit an application and obtain the approval of an officer of the division before

(i) deepening a well beyond the formation from which production is being taken or has been taken,

(ii) recompletion of a well by perforating any casing with a view to producing a geothermal resource from any formation other than that from which production is being taken or has been taken,

(iii) suspending drilling,

(iv) ceasing normal producing operations,

(v) resuming drilling after a previous completion, suspension or abandonment of a well,

(vi) resuming production after a cessation of production,

(vii) reworking a well to alter its producing characteristics, or

(viii) abandoning a well,

and authorizing an officer of the division to direct the conditions under which approval is granted in any such case, and the methods to be employed in a drilling or abandonment operation;

(c) prescribing the conditions under which drilling may be carried out in water covered areas, and any special measures to be taken;

(d) prescribing the measures to be adopted to confine geothermal resources water encountered during drilling to its original stratum, and to protect the contents of the stratum from infiltration, inundation and migration;

(e) prescribing the minimum standard of tools, casing, equipment and materials that may be used for drilling, development and production of geothermal resources;

(f) to regulate the drilling of multizone wells, prohibit completion of a well as a multizone well without the permission of an officer of the division, prohibit the use of a well for the production from or injection to more than one zone without the approval of an officer of the division and authorize the officer of the division to grant his permission or approval subject to conditions the officer of the division considers necessary;

(g) prescribing measures for the protection of petroleum and natural gas deposits, coal seams, mineral deposits and any workings in them;

(h) requiring the provision of adequate well casing and proper anchorage and cementation;

(i) requiring and prescribing samples, tests, analyses, surveys, logs, records, other information respecting a geothermal resource or operation, the method of taking samples and submission of records and information to the division;

(j) prescribing the measures to be taken before drilling begins and during drilling and production to conserve geothermal resources and water;

(k) prescribing or limiting the methods of operation to be used during drilling and in the subsequent management of a well and the conduct of an operation for any purpose, including

  (i) the prevention and extinguishing of fires, and

  (ii) the prevention of wells flowing out of control;

(l) regulating the location and equipping of production facilities;

(m) regulating the conditioning or reconditioning of wells by mechanical, chemical or explosive means;

(n) requiring the inspection of wells both during and after drilling;

(o) requiring the capping or closing in of wells for the purpose of preventing waste;

(p) requiring the cleaning out of a well;

(q) regulating the unitization of a field for drilling and production;

(r) regulating and prohibiting the release of well records and well data;

(s) the naming of wells and production facilities;

(t) measures to contain and eliminate spillage;

(u) regulating production from a geothermal well;

(v) the general conservation of geothermal resources, their waste or improvident disposition, and any matter incidental to geothermal resource wells' development, drilling, operation and production;

(w) the methods and units to be used for the measurement of geothermal resources, and the standard conditions to which the measurements are to be converted.

(2) A regulation made under subsection (1) may provide that the division head may, in relation to a particular location or well and subject to conditions the division head specifies, exempt a person from the application of all or part of the regulation.

(3) Exemptions granted under subsection (2) by the division head or an officer of the division, and regulations made under this section other than regulations of general application, are not regulations for the purpose of the *Regulation Act*.

1982-14-23.

Regulations made by Lieutenant Governor in Council

24. (1) The Lieutenant Governor in Council may make regulations for the purposes of this Act, or respecting geothermal resources.

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations for the following purposes and respecting the following matters:

(a) establishing the conditions under which persons are eligible to apply for the issue and renewal of permits, leases, test hole program authorizations, well authorizations, geothermal rig licences, registrations, recordings and other rights, privileges and services under this Act or the regulations, and the procedures to be followed and the fees to be paid by them;

(b) the revocation and suspension by officers of the ministry in circumstances specified in the regulations of permits, leases, test hole program authorizations, well authorizations and geothermal rig licences and the powers to be exercisable by those officers for those purposes;

(c) the application, with or without modification, of regulations made under section 36 of the *Petroleum and Natural Gas Act* respecting geophysical exploration, to exploration for geothermal resources;

(d) requiring persons holding leases to submit plans for any work that they propose and prohibiting the carrying out of that work without approval;

(e) establishing the conditions under which permits, geothermal rig licences, leases, test hole program authorizations and well authorizations may be transferred;

(f) royalties and the amount or rate of a royalty that shall be paid in cases where there is no agreement under section 17;

(g) prescribing the rent payable in respect of leases;

(h) prescribing the amount or method of calculation of security deposits required under the Act;

(i) establishing the amount and kind of work to be performed by permittees and lessees on their locations and the time within which the work is required to be done, providing for grouping, unitization, payments in lieu of work and related matters, and authorizing, in circumstances specified in the regulation, the extension of time within which work required to be done on a location may be done where the permittee or lessee has been prevented from doing work by extraordinary physical conditions that are beyond his control and could not be foreseen by him;

(j) requiring lessees to provide surveys of their locations at their expense and setting standards for the surveys;
(k) establishing procedures for recording transfers and other instruments affecting the title to permits and leases;
(l) the granting, in respect of a test hole or well drilled or in operation before this Act came into force, of exemptions from provisions of this Act other than section 2;
(m) to meet any difficulties that may arise by reason of the repeal of the *Geothermal Resource Act* and the substitution of this Act;
(n) requiring persons drilling for or producing geothermal resources to keep records, and prescribing the information to be recorded in those records;
(o) requiring persons drilling for or producing geothermal resources to
  (i) supply samples and cores,
  (ii) disclose geological information respecting the resources
obtained by them in the course of the drilling and production.

1982-14-24.

Consequential Amendments

25 to **28.** [Spent. 1982-14-25 to 28.]

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I.2 Other Acts

The following acts also have some significance in their application to the development and marketing of geothermal resources:

B.C. Hydro and Power Authority Act
B.C. Pollution Control Act
B.C. Pipe-lines Act.
B.C. Workers Compensation Act
B.C. Mining Tax Act
B.C. Corporation Capital Tax Act
B.C. Municipal Act
B.C. Factories Act
Canada Income Tax Act
Canada National Energy Act
Canada Water Act
Canada Clean Air Act
Canada Fisheries Act
Canada Northern Inland Waters Act
Canada Territorial Lands Act

For futher discussion and commentary, see the following:

United States House of Representatives, 95th Congress, Publication Number 29-5110.

Mining in Environmental Law, Mineral Resources Branch, Department of Energy, Mines and Resources, Mineral Bulletin MR 138, 1973

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Oil and Gas Conservation Act and Regulations, Alberta Statutes, July 1979.

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GEOTHERMAL ENERGY RESOURCES IN BRITISH COLUMBIA

EXECUTIVE SUMMARY

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GEOTHERMAL ENERGY RESOURCES IN BRITISH COLUMBIA

A study of factors affecting development and utilization

EXECUTIVE SUMMARY

Prepared for

Ministry of Energy, Mines and Petroleum Resources
of the Province of British Columbia

by

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GEOTHERMAL ENERGY RESOURCES IN BRITISH COLUMBIA

A study of factors affecting development and utilization

EXECUTIVE SUMMARY

INTRODUCTION

Geothermal energy is heat generated and stored within the earth. A small fraction of this heat can be tapped and utilized--either directly or after conversion to electricity.

Three types of geothermal reservoirs lend themselves to utilization and are of principal interest here: hydrothermal reservoirs dominated by steam; hydrothermal reservoirs dominated by pressurized hot water; and systems of deeply circulating water in faults or porous aquifers.

The two types of hydrothermal systems occur in areas of recent volcanic activity. Wells drilled into a steam-dominated system can yield high-grade dry steam suitable for driving turbine generators directly. Wells drilled into a water-dominated hydrothermal system which has the right characteristics can produce a large flow of superheated water, a fraction of which can be separated as wet steam and similarly used to drive turbine generators. Steam or hot water from a hydrothermal system or hot water from a deep circulating system, if certain conditions of temperature, pressure and rate of flow are met, can be used directly to heat buildings, supply industrial process heat, or for dozens of other applications, including greenhouses and fish hatcheries.

Geothermal energy is a stationary power source. If it is converted to electricity, the generating plant is invariably located at the site of the deposit. If the thermal energy is used directly, without conversion to electricity, the application is generally located within 10 kilometers of the site.

The mechanics of geothermal energy development are simple and straightforward. Wells are drilled into the reservoir, commonly to a depth of 1 000 meters, or as much as 3 000 meters for a high value resource. The wells are completed (cased or lined) for production and wellhead valves and gauges are installed. Several wells are connected by means of a gathering system and manifold. In the case of an electric conversion plant, steam separators and rock chip separators are installed in the system, and the steam transmission pipes lead directly to the turbine generator. In the case of a direct application, water or steam transmission pipes lead to the plant or to a distribution system which services customers.

In electrical conversion plants a fraction of the geothermal fluid evaporates, generally from cooling towers, and a fraction is discharged from the plant as hot water waste. The temperature of the waste may approach boiling and it may contain dissolved solids, such as silica and salts of sodium, calcium, sulfate, carbonate and chloride. Current practice in most geothermal electric fields is to reinject liquid waste into the ground or reservoir by means of disposal wells. The liquid waste product from a direct-use application is sometimes reinjected, or if the temperature and dissolved solid content are low enough to meet environmental standards, waste may be discharged on the surface into a normal drainage.

Dissolved gases are present in many geothermal fluids. Some are harmless, such as carbon dioxide or nitrogen. The most troublesome is hydrogen sulfide, which mandates abatement equipment if present in quantity.

HISTORY AND PROJECTION OF WORLD GEOTHERMAL DEVELOPMENT

The earliest geothermal installations were developed at boiling springs or geysers, where the applications were obvious to nearby inhabitants or entrepreneurs. Systematic use, for other than recreational spas, began in Iceland in the 13th century, when hot springs were developed for municipal heating. The system has grown to serve most of the heating needs of the 110 000 residents of Reykjavik. The first electrical generating plant was installed in 1904 at Larderello, Italy. This field has been in nearly continuous operation since that time and has been incrementally developed to approximately 200 megawatts capacity.

The combined total of recorded direct use installations in the world, as of November 1980, is a capacity of 7 000 megawatts (thermal), or 25 000 kilojoules per hour. In addition to Iceland, the countries which lead in direct utilization of geothermal energy are the USSR, Hungary, New Zealand, and the United States.

Present worldwide electric generating capacity is about 1 800 megawatts, deriving from 34 geothermal fields in 12 countries. The current leader is the United States, where 900 megawatts are installed at The Geysers geothermal field in California. Several other system-electric plants are in operation or in final construction stages on six other fields in U.S. localities. Other important electric conversion plants are located in El Salvador, Iceland, Japan, Mexico, New Zealand and the Philippines.

The 1970's marked a turning point in world energy prices. This turning point has affected geothermal energy exploration and development as well, with accelerated work worldwide, the extent of which will become more clear as the 1980's unfold.

Geothermal electric capacity worldwide grew at a rate of approximately 7% per year during the 3½ decades starting in 1940. It is too early to project the rate of growth into the next several decades, but the projects in construction or advance planning stages suggest a growth rate of 19% per year onward from 1975 (Muffler and Guffanti, 1979). Research, exploration and development are being conducted in at least 30 countries which have no current geothermal generating capacity. Canada is one of those countries, and British Columbia is the current locus of such exploration activity.

Geothermal technology draws from previously developed geology and geophysics, oil drilling technology, space-age materials and metallurgy, and the latest in computing and data processing technology. Current research is directed toward state-of-the-art advances in drilling tools and downhole logging instruments capable of withstanding high temperatures, mathematical modelling of fluid flow in geothermal reservoirs, conversion of greater fractions of the total energy content of the geothermal fluid to electricity, and handling of corrosive or briny fluids.

It is axiomatic that exploration must precede development. Early geothermal installations utilized obvious resources and involved little exploration. The industry has now moved toward seeking out the many blind targets in the world. In this regard, geothermal energy development is following the path of the other extractive and mineral industries: oil was originally collected from surface seeps and now a highly sophisticated technology finds oils where there is no direct evidence at the surface; metals were first dug out of outcrops, and now geology and geophysics discover deeply buried deposits.

The craft of exploration for geothermal resources is highly developed and uses tools perfectly matched to the commodity. Systematic geothermal exploration programs scout a large area for direct and indirect evidence, such as recent volcanic rocks, throughgoing faults and fractures, zones of rock alteration or fossil hot spring deposits, until eventually several prospective areas are selected for geophysical work and drilling. As work progresses, some prospects are abandoned and the program zeroes in on those with high temperature gradients and high heat flows. The best of these prospects are drilled for a geothermal discovery.

GEOTHERMAL RESOURCE AREAS IN BRITISH COLUMBIA

Systematic geothermal exploration in British Columbia has been underway since 1973. The principal project is steam exploration by the British Columbia Hydro and Power Authority at Meager Creek, 75 km northwest of Pemberton. A drilling program, aimed at a discovery in 1981 or 1982, is in progress.

Aside from the few hot springs which are developed as resorts, there are no proven geothermal reserves in B.C. at present. The resource base is presumed to be quite large, but is still untested, unproven and unknown.

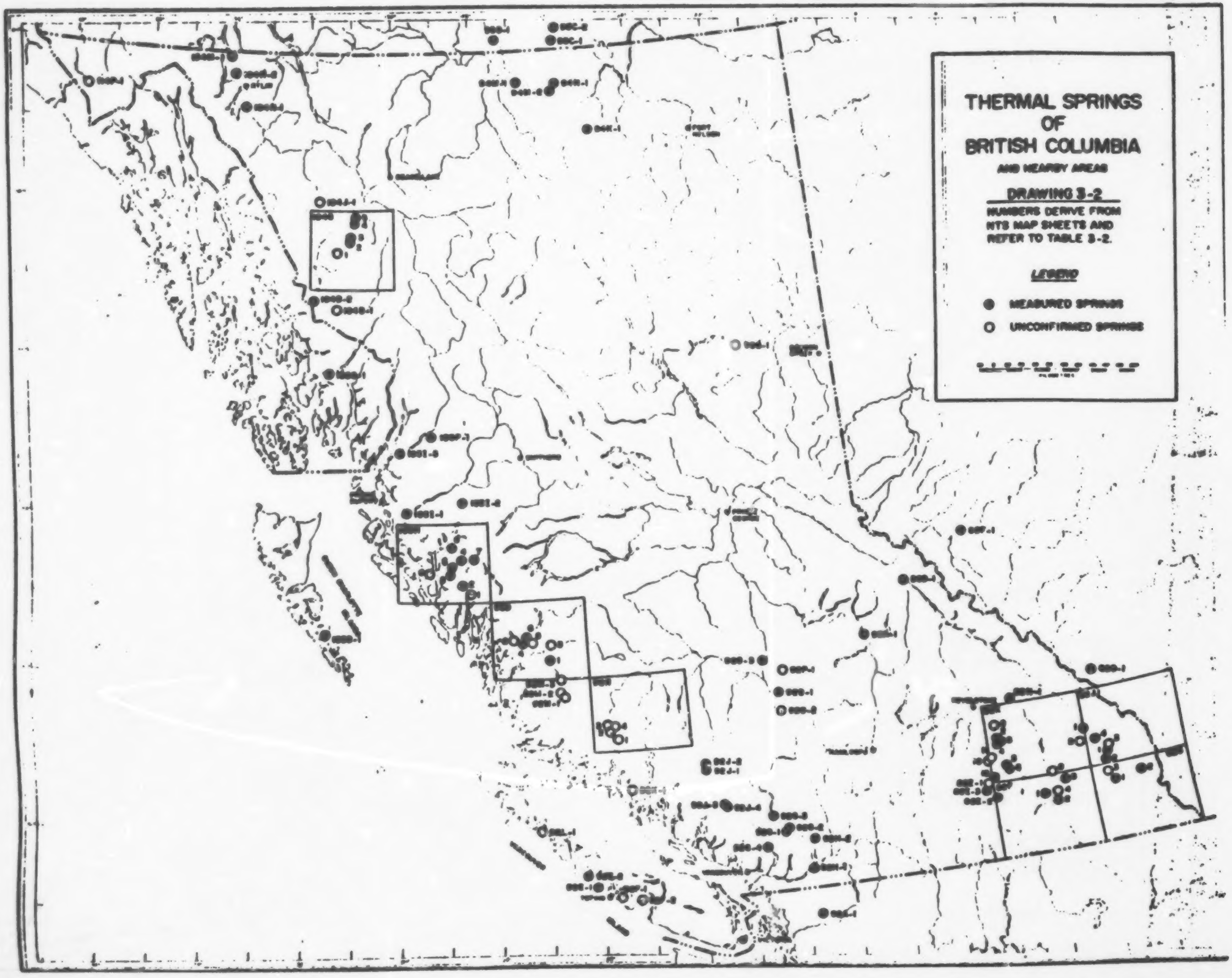
Evidence for the extent of the resource base in British Columbia is shown in Drawings 3-2 (hot springs) and 3-3

- - - - - - - - - - - - - - - -

Drawings 3-2 and 3-3 follow

- - - - - - - - - - - - - - - -

(volcanos). Thermal springs number about 100 and some of these occur in a geologic terrane and have chemical characteristics which imply that they derive from high temperature hydrothermal systems. About 25 late Cenozoic volcanic complexes also occur in and near British Columbia. Some may overlie chambers of molten or crystallizing rock, at depths of 15 or 20 kilometers, which give off enough heat to drive a hydrothermal convection cell at a depth of 2 or 3 kilometers.



THERMAL SPRINGS
OF
BRITISH COLUMBIA
AND NEARBY AREAS

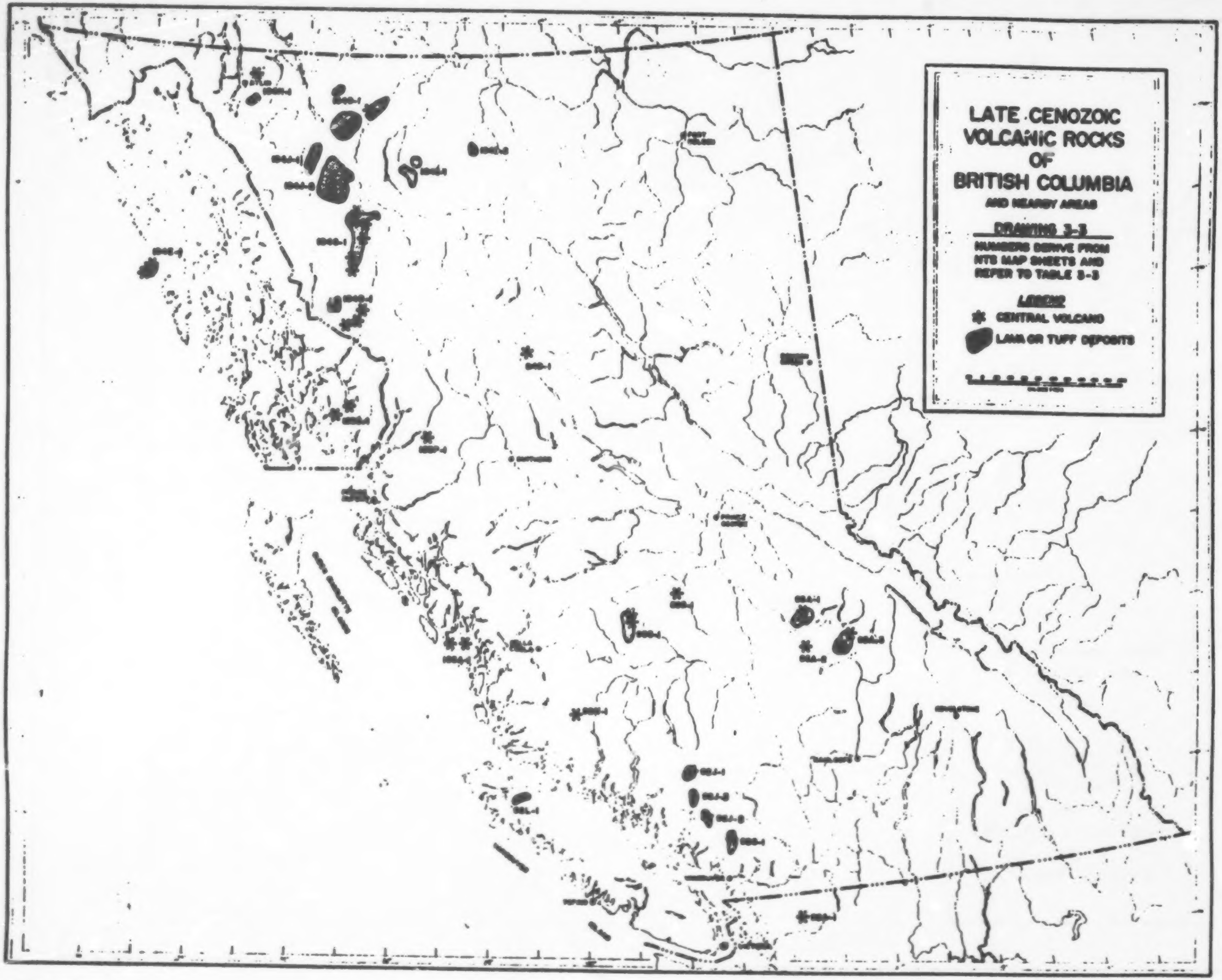
DRAWING 3-2

NUMBERS DERIVE FROM
NTS MAP SHEETS AND
REFER TO TABLE 3-2.

LEGEND

● MEASURED SPRINGS

○ UNCONFIRMED SPRINGS



* CENTRAL VOLCANO
LAVA OR TUFF DEPOSITS

LATE CENOZOIC VOLCANIC ROCKS OF BRITISH COLUMBIA

AND NEARBY AREAS

DRAWING 3-3

NUMBERS DERIVE FROM NTS MAP SHEETS AND REFER TO TABLE 3-3

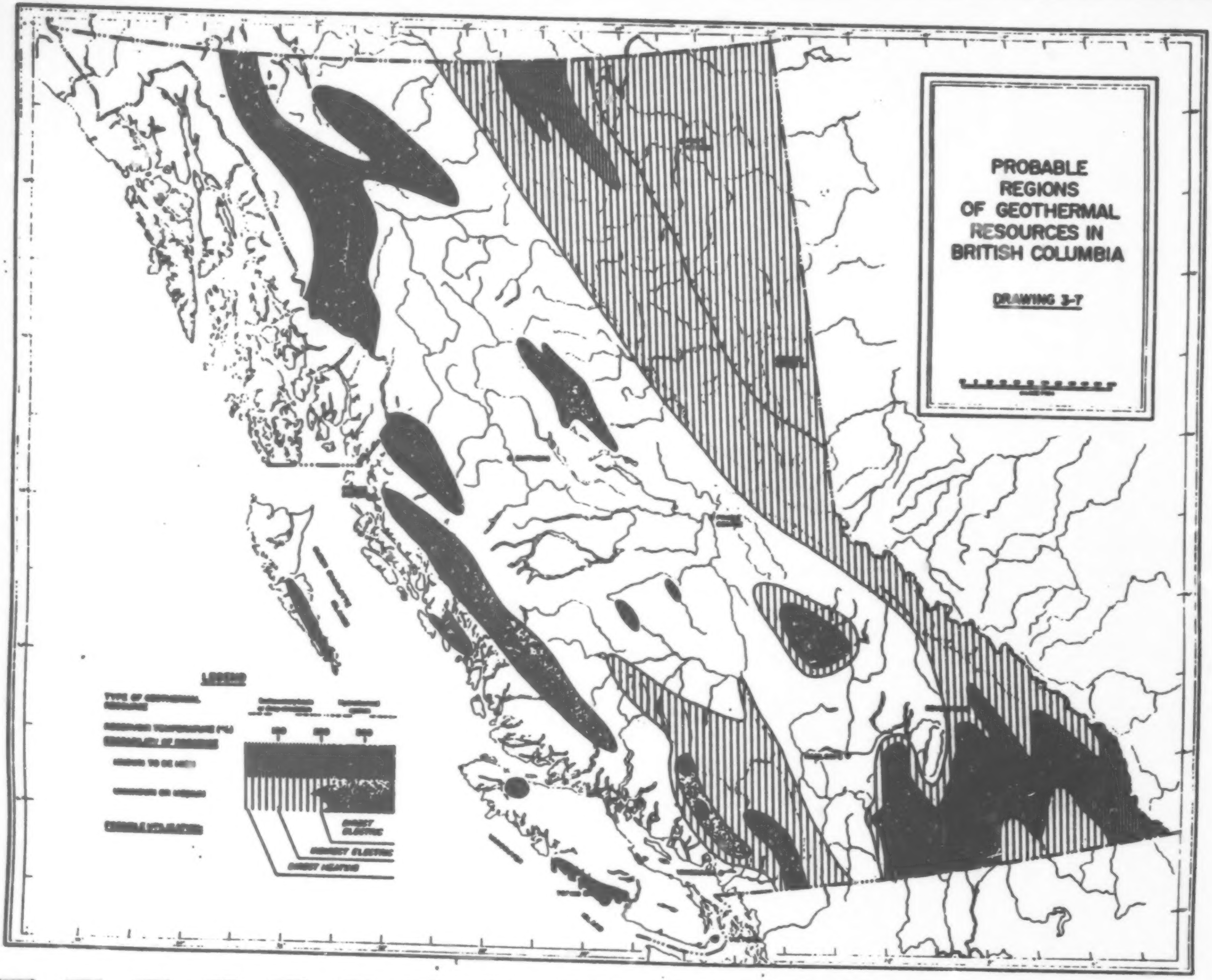
Areas within British Columbia which we consider to have potential for high-temperature geothermal resources are shown in Drawing 3-7 and are described as follows:

- - - - - - - - - - -

Drawing 3-7 follows

- - - - - - - - - - -

1. Southwestern mainland: Two areas trending northwest from Mt. Baker (Washington) and extending to the Meager Creek volcanic system, 75 km northwest of Pemberton; including parts of the Squamish and Lillooet River drainages.
2. Okanagan: large block faulted terrane, extending east from the Okanagan drainage to the longitude of Grand Forks.
3. Vancouver Island: Two areas of unknown probability for high-temperature hydrothermal resources, one elongate northwest at Tofino; the other related to a major east-west fault near Port McNeill.
4. Queen Charlotte Island: A northwest trending zone bisecting Moresby Island.
5. Northern Coast: Several zones elongate northwest and extending through Bella Coola, Klemtu, Douglas Channel, Terrace, and the Nass River.
6. Northwestern BC: A large area including the volcanic terrane of Mt. Edziza, much of the Stikine and Iskut River drainages, the Spatsizi Plateau and extending northwest through Atlin.


PROBABLE
REGIONS
OF GEOTHERMAL
RESOURCES IN
BRITISH COLUMBIA
DRAWING 3-7
LEGEND
DIRECT ELECTRIC
INDIRECT ELECTRIC
DIRECT HEATING

7. Central Interior: At least four areas distributed among the scattered late Cenozoic volcanos, near Wells Gray Park in the south, to the Sustut area in the north.

These areas, in our opinion good starting places for exploration for high-temperature resources, would be equally appropriate for exploration aimed at geothermal resources for space heating or other low-temperature applications.

The eastern part of the province clearly has low-temperature geothermal resources, scattered throughout the Rocky Mountains, and in the sedimentary basins of the northeast. Low temperature means 200°C or less, too low to be considered a strong candidate for electric generating with existing technology. We expect that most of the resources in eastern British Columbia will be found to have maximum temperatures of 100°C or less.

There are numerous known thermal springs in southeastern B.C., between the Arrow Lakes and the Alberta border. These derive from deep circulation of water along overthrust faults and through permeable sedimentary rocks. Similar geology and hot springs are present in northern British Columbia, near Liard Crossing. Strong potential exists for the discovery of new, deep-circulating geothermal systems virtually anywhere in the folded and faulted Rocky Mountain belt.

Certain aquifers and gas and oil producing beds in the sedimentary basins of Northeastern British Columbia are known to contain hot brines. Some of these fluids reach 70°C or

100°C in temperature. These constitute a part of the geothermal resource base which may be useful at some future time. At present development is not worthwhile. The oil and gas in the region have much higher specific value and specific heat content than geothermal fluids, and high-density, centralized markets for low temperature heating are very few.

ECONOMIC MODELS

Actual economic feasibility of any given geothermal project cannot be determined until such time as the geothermal resource is discovered, proven, measured, and analyzed as to physical and chemical characteristics. Four generalized economic models have been set up and analyzed as to the capital and energy costs. These economic models are based on geothermal projects elsewhere and on conditions within British Columbia. In general the models follow a reasonable middle-of-the-road course, i.e., they are neither the most economical nor the least economical in the range of the hypothetical alternatives. The models are:

1. A 50 megawatt system-electric plant
2. A 1 500 kilowatt local-electric plant
3. A space heating system for a community of 3 000 population
4. A trout farm producing 900 000 kilograms per year.

The absolute and relative amounts of energy utilized or converted for each of these model systems are shown in Drawing

7-2. To put the energy transfer into perspective, the heat

- - - - - - - - - - - -

Drawing 7-2 follows

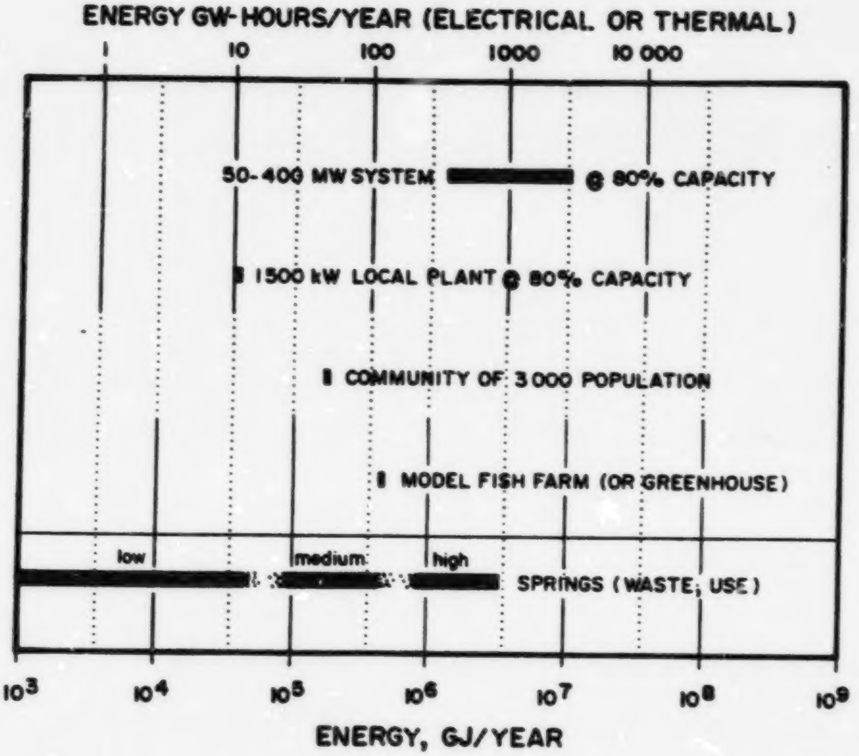
- - - - - - - - - - - -

wasted by various thermal springs in the province is also shown, classified as high, medium or low heat loss. (This comparison is concerned with energy or heat and is independent of temperature. For example, although a 1 500 kW electric plant consumes only 1/100th of the energy wasted by a powerful hot spring, the temperature needed for an electric plant is more than 200°C, while even the hottest of the thermal springs in British Columbia generally do not exceed 70°C.)

System Electric Model

The system electric model is the most important and was analyzed from several different standpoints. A geothermal reservoir capable of system electric utilization is the highest value type of geothermal resource, and the system electric utilization makes the largest contribution to society. The following assumptions and parameters served as a basis for the system electric model:

1. The characteristics of three separate types of geothermal reservoir were analyzed. Case 1 is a dry steam field similar to The Geysers, California. Case 2 is a high temperature water-dominated field similar to the Roosevelt field, Utah, or Valles Caldera, New Mexico.



DRAWING 7-2

ANNUAL ENERGY TRANSFER
OF MODEL SYSTEMS, AND
THERMAL SPRINGS

Case 3 is a moderate-temperature (180°C) water-dominated field modelled after East Mesa, California.

The conversion systems for each of these models is shown schematically in Drawing F-1: Case 1 uses No. 1;

- - - - - - - - - - - -

Drawing F-1 follows

- - - - - - - - - - - -

Case 2 uses No. 2 or 3; Case 3 uses No. 5.

2. The geothermal fluids are relatively clean, i.e., low salinity, low non-condensable gas, and low hydrogen sulfide content, such that no abatement equipment is necessary.

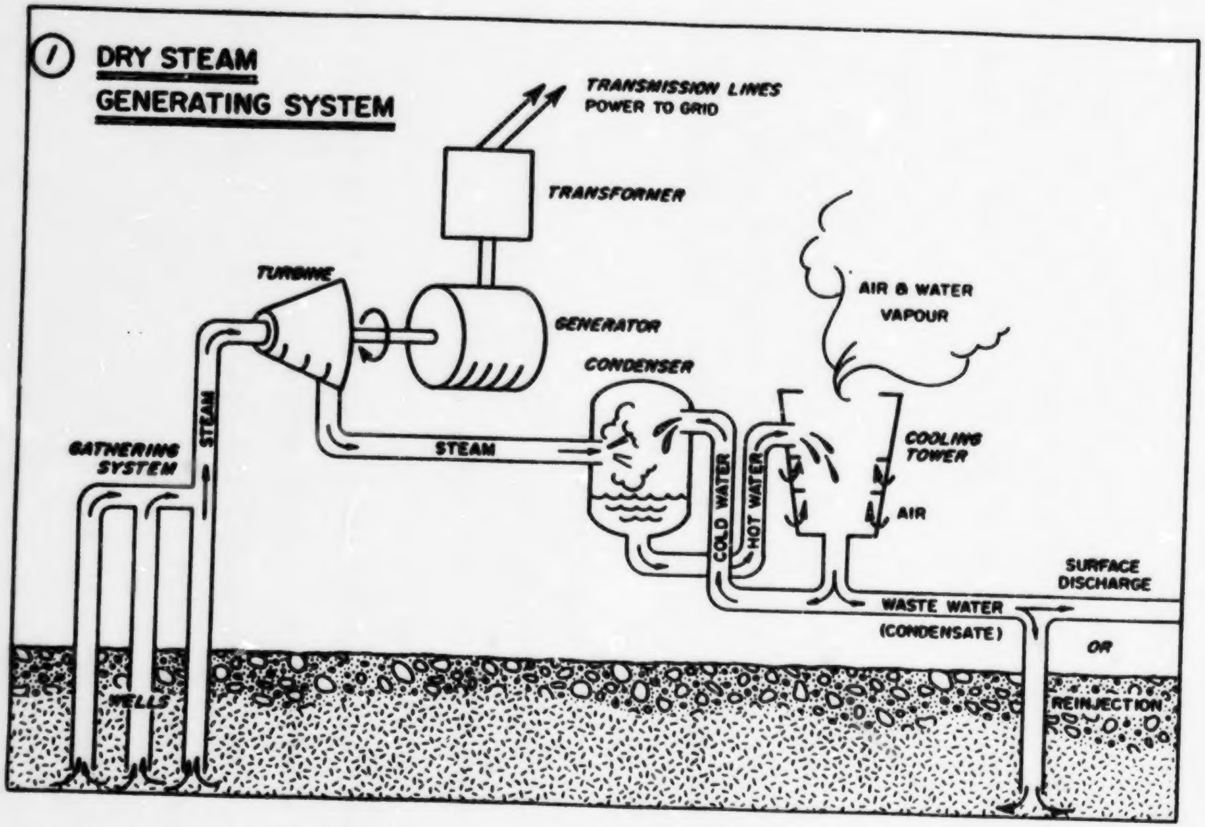
3. Drilling depth to the reservoir is 1 500 to 2 000 meters, and production wells cost $1 600 000 each.

4. Pre-production exploration expense is $10 000 000 (1980 Canadian dollars are used throughout unless otherwise noted).

5. In the instance where the 50 MW plant is incremented to 400 MW, $5 000 000 is charged for exploration for each 50 MW increment, or $100/kW.

6. Liquid waste is reinjected into the reservoir by means of disposal wells, which cost exactly as much as production and standby wells.

7. The time period for operation is the 30 years from 1991 through 2020.

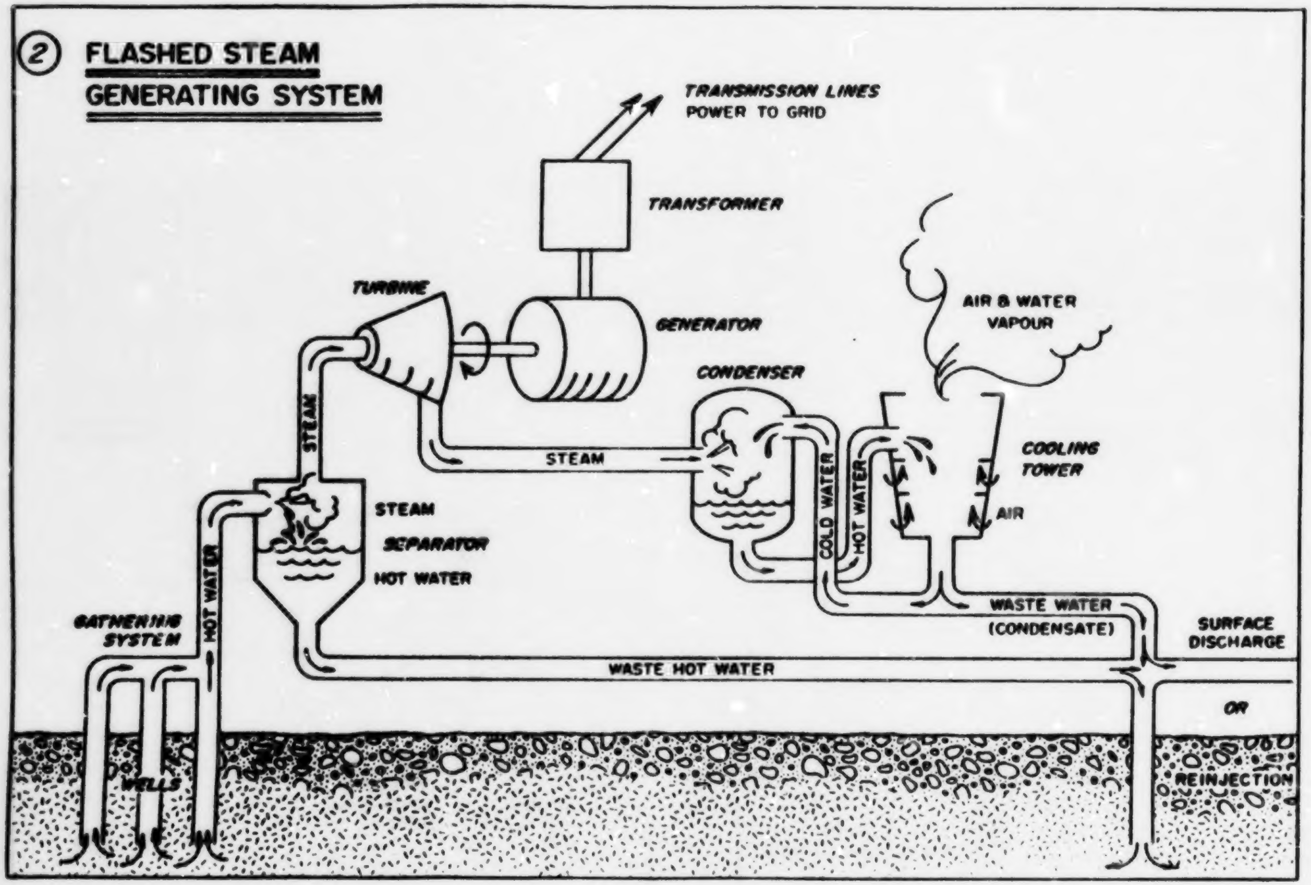

①
DRY STEAM
GENERATING SYSTEM
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
CONDENSER
AIR & WATER
VAPOUR
COOLING
TOWER
AIR
GATHERING
SYSTEM
STEAM
STEAM
COLD WATER
HOT WATER
SURFACE
DISCHARGE
WASTE WATER
(CONDENSATE)
OR
REINJECTION
WELLS

DRAWING F-1

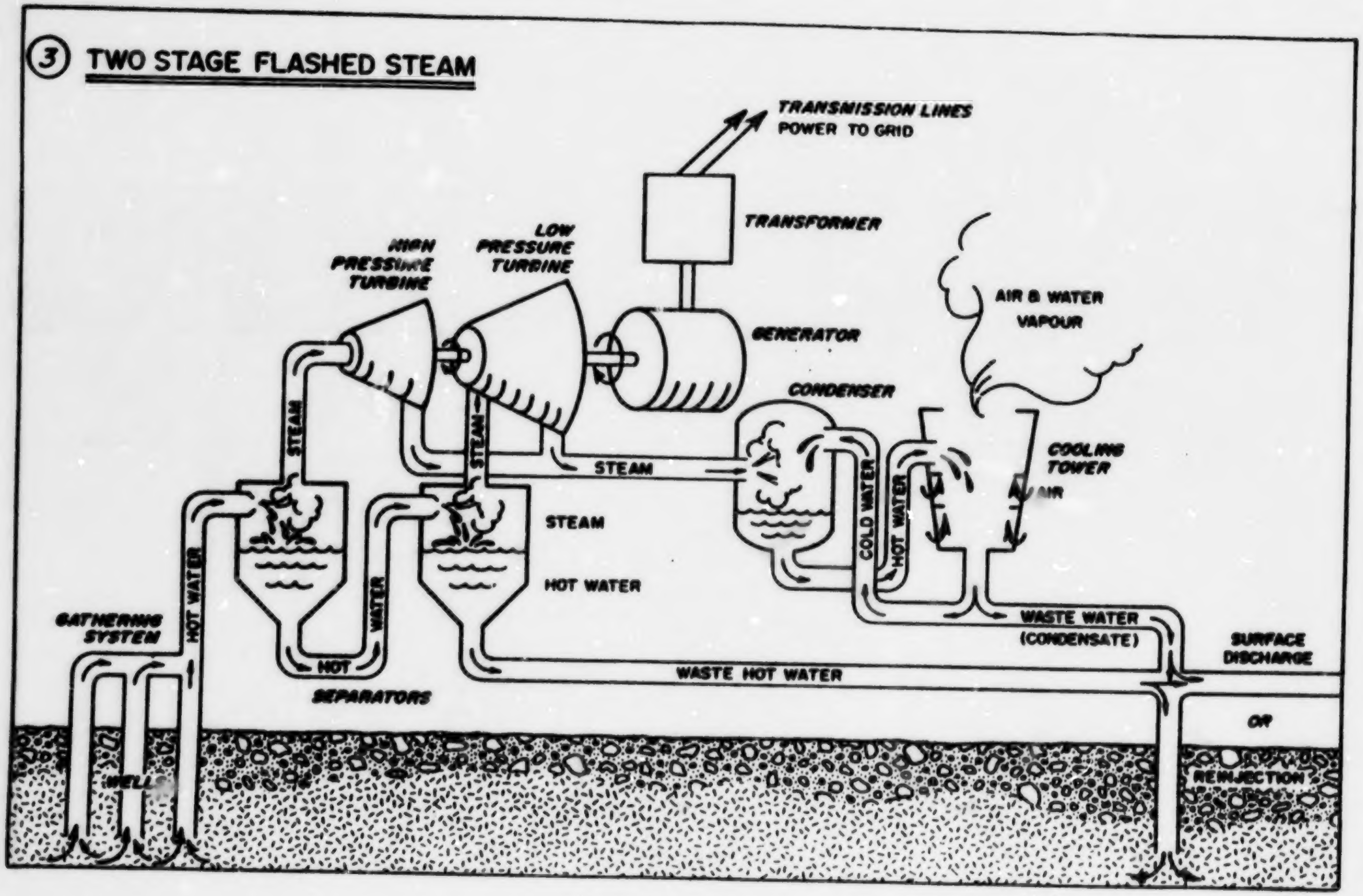
FIVE REPRESENTATIVE TYPES
OF GEOTHERMAL
GENERATING PLANTS

See text for discussion.

Continued overleaf /2


② FLASHED STEAM
GENERATING SYSTEM
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
AIR & WATER
VAPOUR
CONDENSER
STEAM
STEAM
COOLING
TOWER
STEAM
SEPARATOR
HOT WATER
COLD WATER
HOT WATER
AIR
GATHERING
SYSTEM
HOT WATER
WASTE WATER
(CONDENSATE)
SURFACE
DISCHARGE
WASTE HOT WATER
OR
WELLS
REINJECTION

DRAWING F-1 (cont'd)

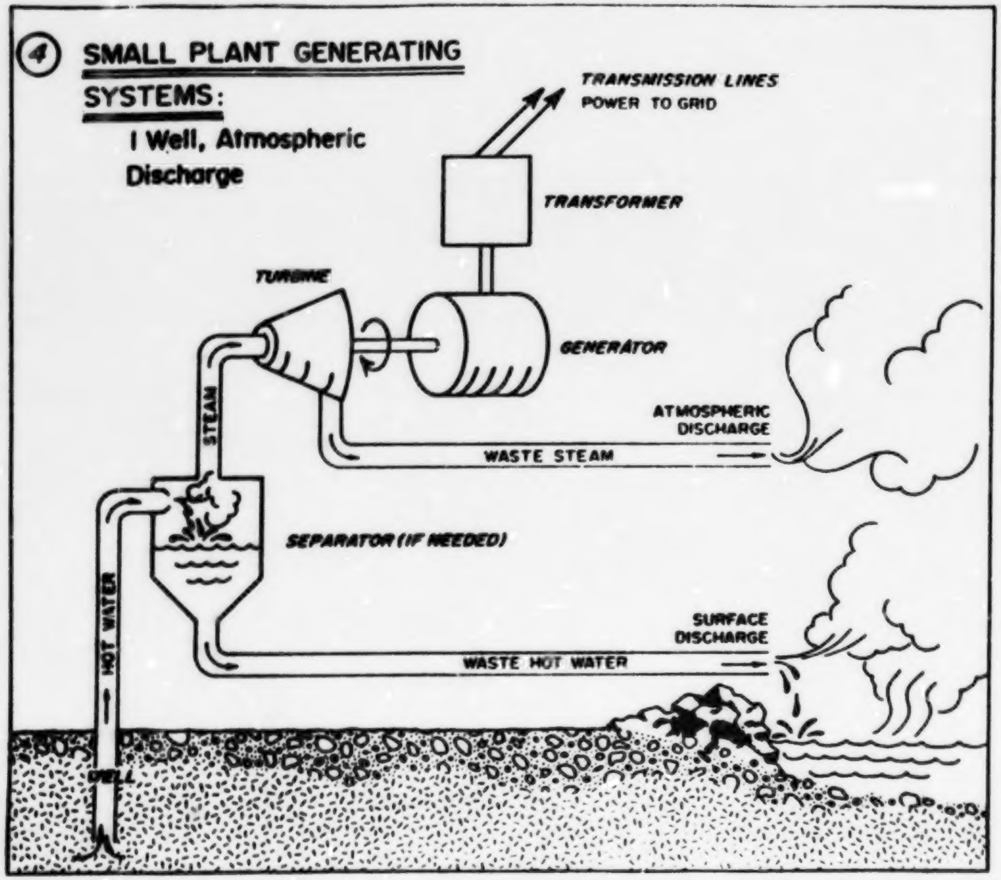


③ TWO STAGE FLASHED STEAM

TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
HIGH PRESSURE TURBINE
LOW PRESSURE TURBINE
GENERATOR
CONDENSER
AIR & WATER VAPOUR
COOLING TOWER
AIR
STEAM
STEAM
STEAM
STEAM
HOT WATER
COLD WATER
HOT WATER
GATHERING SYSTEM
HOT WATER
HOT WATER
SEPARATORS
WASTE WATER (CONDENSATE)
WASTE HOT WATER
SURFACE DISCHARGE
OR
REINJECTION
WELLS

DRAWING F - I (cont'd)

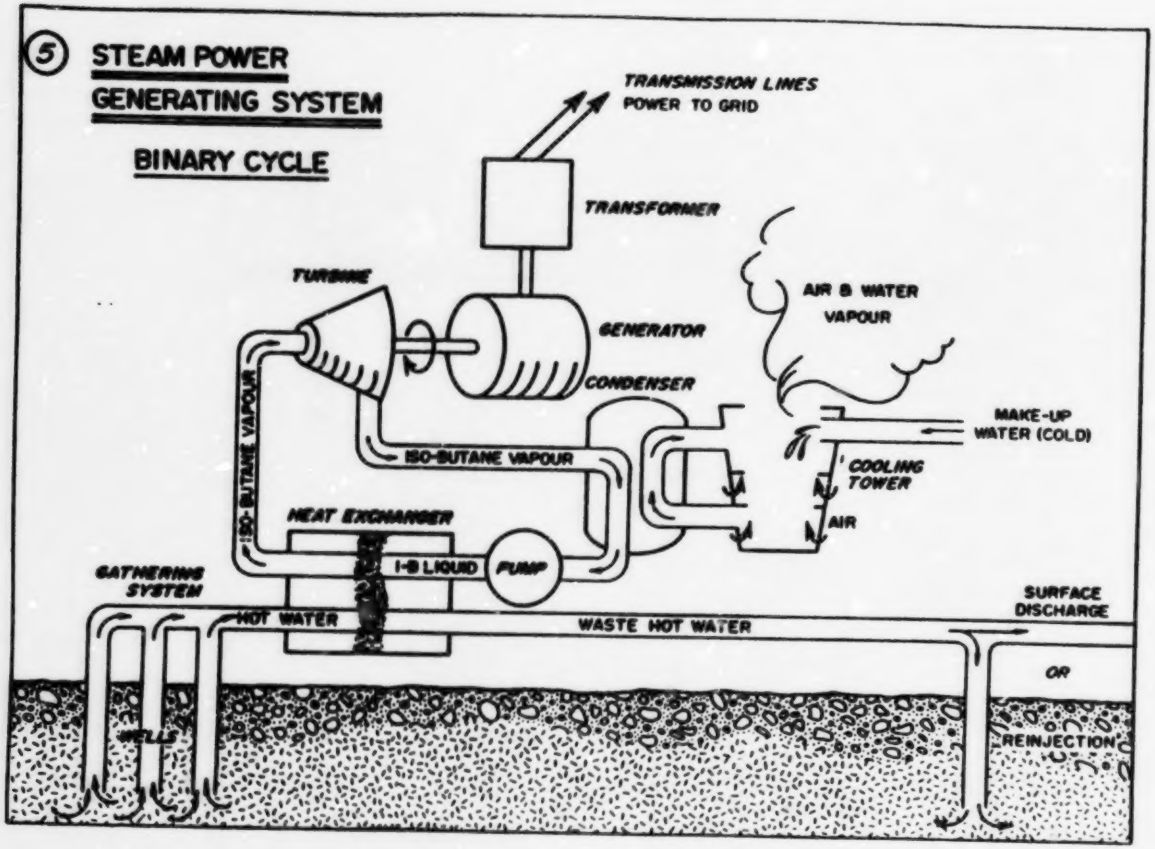
.../4



④ SMALL PLANT GENERATING
SYSTEMS:
I Well, Atmospheric
Discharge
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
STEAM
ATMOSPHERIC
DISCHARGE
WASTE STEAM
SEPARATOR (IF NEEDED)
HOT WATER
SURFACE
DISCHARGE
WASTE HOT WATER
WELL

DRAWING F-I (cont'd)

.../5



⑤ STEAM POWER
GENERATING SYSTEM
BINARY CYCLE
TRANSMISSION LINES
POWER TO GRID
TRANSFORMER
TURBINE
GENERATOR
CONDENSER
AIR & WATER
VAPOUR
MAKE-UP
WATER (COLD)
COOLING
TOWER
AIR
ISO-BUTANE VAPOUR
ISO-BUTANE VAPOUR
HEAT EXCHANGER
I-B LIQUID
PUMP
GATHERING
SYSTEM
HOT WATER
WASTE HOT WATER
SURFACE
DISCHARGE
OR
REINJECTION
WELLS

DRAWING F-1 (cont'd)

8. The reservoir is in the Lower Mainland and 75 km of transmission lines and minor switching equipment are installed as part of the capital cost of the project.

9. Capacity factor is 80%; this is higher than the average for most systems; however, two factors favor the use of a high capacity factor. First, it is a characteristic of geothermal power plants to operate at high capacity factors, and secondly, it is consistent with the needs of the existing grid in British Columbia.

10. The average well life is 15 years, and all production wells are redrilled once during the plant life.

11. An additional capital cost of $5 000 000 is charged in year 2000 to provide 11.4 MW of peaking capacity.

12. Levelized energy costs are calculated according to accepted utility company practice at discount rates of 3, 6 and 10 percent, and the results of each calculation are given.

The capital cost summaries and energy cost summaries are shown in Table 1. The dry steam geothermal plant--the least complicated plant, on the most valuable resource--has an energy cost which is estimated to range between 18.3 and 32.4 mills/kWh, depending upon the discount rate used in the evaluation.

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Table 1 follows

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TABLE 1. Summary of Geothermal Energy Costs from 50 MW Plants on Three Model Fields

Case (Basis is Quality of Reservoir)[1]	Available Wellhead Energy (kJ/kg)	Number of Wells Required; Total well Cost ($millions)[2]	Generating Plant Type; Capital Cost ($millions)	Total Capital Costs per kWh ($); Total Capital Costs ($millions)[3]	Levelized Total Energy Costs (in mills/kWh)[4] a utility's discount rate of:		
					3%	6%	10%
1. Dry Steam	880	7	direct	1 400	18.3	23.7	32.4
100% steam		11	30	72			
2. Wet Steam	305	17	flashed-steam	1 900	24.8	31.8	43.4
20-35% steam		27	38	95			
3. Hot Water	150	40	binary	3 200	41.8	53.2	71.8
0% steam		64	60	159			

[1] The dry steam reservoir is at 240°C and is analogous to the Geysers, California; Case 2 is analogous to Roosevelt, Utah, and is at 270°C (despite the higher temperature it has lower heat content); Case 3 is analogous to East Mesa, California, and is at 180°C.

[2] Includes production, reinjection (waste disposal), and spare wells.

[3] Costs other than well field and plant are included, viz. $10 million capitalized exploration, gathering system, 75 km transmission lines, etc.

[4] Operating, maintenance and administration costs are included; one component is redrilling wells after 15-year life; life of plant is 30 years, 1991-2015; capacity factor is 80%.

Case 2--the flashed steam system--varies between 24.8 and 43.4 mills/kWh, again sensitive to the discount rate.

Case 3 envisions a binary conversion plant and results in an energy cost ranging between 41.8 and 71.8 mills/kWh. Binary plants are a relatively recent technology, and the largest currently installed is 11 MW. The results calculated for Case 3 are consistent with the record of that binary plant.

Cases 1 and 2 appear to be economic under most standards; Case 3 appears to be high cost energy which would not be developed on economic criteria alone. In order to compare geothermal energy with other sources of undeveloped energy currently available to the utility system in British Columbia, published figures on the proposed Site C hydroelectric project and the proposed Hat Creek coal-fired thermal plant were used to develop similar models at the various discount rates. The comparison is shown in Table 2. Hydro power is quite sensitive to the discount rate; coal-fired thermal power is the least sensitive. This is evident in their respective ranges 13 to 37 mills/kWh and 28 to 44 mills/kWh.

- - - - - - - - - - - -

Table 2 follows

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Geothermal energy appears to be competitive on an economic basis with both hydro and coal-fired thermal energy,

TABLE 2. Comparison of Costs of Alternative Power Sources and Operators, Levelized in 1980 mills/kWh

A. Development by Utility

Utility's Discount Rate (%)	Hydro[1] (Site C)	Thermal[1] (Hat Creek)	Geothermal 50 MW Case 1	Geothermal 50 MW Case 2	Geothermal 50 MW Case 3	Geothermal 400 MW[2] Case 1	Geothermal 400 MW[2] Case 2
3	13	28	18	25	42	15	20
6	22	34	24	32	53	19	25
10	37	44	32	43	72	26	35

B. Development Involving Private Sector

	Case 2	Private Field Utility Plant[3] Lowest Cost	Private Field Utility Plant[3] Highest Cost	Entire Development Private Company[4] Lowest Cost	Entire Development Private Company[4] Highest Cost
3	25	30	47	38	51
6	32	34	51		
10	43	39	56		

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[1] Based on published information believed to be reliable.

[2] Economies of scale in capital costs--the most sensitive element in geothermal--are estimated to produce energy for 80% of the 50 MW plant when incremented to 400 MW.

[3] A "resource company" sells steam to the utility's generating plant; 51% federal and provincial income tax assumed; 100% exploration write off, 30% deprection schedule for wells; lowest cost model assumes 75% debt-financing at 11% interest and 20-year retirement, and 17% return on equity; highest cost assumes no debt and 20% return on equity.

[4] A "resource company" develops field, generates and sells electricity; utility's discount rate not applicable; 75% debt-financed at 11% interest; lowest cost assumes no federal-provincial income taxes and 17% return on equity; highest cost assumes 51% income taxes and 20% return on equity.

subject to the accuracy of the assumptions, or more particularly, subject to the ability of exploration geologists and development engineers to meet or to better the various conditions laid out.

Based on the 50 MW model, which in the British Columbia electric system could be regarded as only a pilot scale plant, costs for 400 MW were estimated. Capital costs employ economies of scale for field development and generating plant installation at a savings of 15 to 30% from the 50 MW model. The energy cost for a 400 MW plant operating at 80% capacity factor is estimated to be about 80% of that for the 50 MW plant.

The foregoing projections were done on the basis of cost, where the utility company is the sole explorer and developer. Various models were also calculated using economic parameters characteristic of a company in the private sector of the economy. The flashed steam system was re-evaluated under the assumption that a resource company would discover the deposit, drill and complete the wells, install steam transmission lines and separators, and would sell the steam to the utility's generating plant. The utility would be responsible for generation and transmission. This model is not fictitious; it is in common use in the United States. The resource developers are commonly oil companies.

Nine such models were calculated as to the final energy cost to the utility. This cost is the sum of payments made to the field operator and the cost of generating and transmission facilities borne by the utility. The discount rates used by the utility for its capital investment are 3, 6 and 10 percent. The lowest cost energy available to the utility under this model is 30 mills/kWh and the highest cost is 56 mills/kWh.

The financial parameters common to the highest and lowest cost are as follows:

1. 51% combined federal and provincial income tax on the field operator's earnings;
2. The operator obtains a 100% exploration tax credit during the year of expenditure;
3. A 30% depreciation schedule is available for completed wells, and a flatter depreciation schedule for the gathering and transmission system.

The lowest cost model--from 30 to 39 mills depending upon the utility's discount rate--assumes that the field operator obtains 75% of his post-exploration capital as debt at 11% interest, with a 20-year retirement period. It is further assumed that the operator obtains a 17% return on the equity portion of the investment. The highest cost model differs in that it assumes 100% equity financing and the operator obtains 20% return on the investment. The combined cost model is sensitive to the proportion of debt, tax credits, and return on investment, and is less sensitive to the utility's discount rate or a shortened amortization schedule, such as 15 years.

A third set of models assumes the entire geothermal field and generating plant development by a company in the private sector. The developer sells electrical energy as an investor-owned utility. Held constant is 75% post-exploration debt financing. Return on equity was varied between 17 and 20%, federal income tax was varied between 0 and 36% and provincial income tax was varied between 0 and 15%. The lowest levelized energy cost is 35mills/kWh, on a basis of no income taxes and 17% return on equity. The highest energy cost is 51 mills/kWh, based on full 51% income taxes and 20% return on equity.

The "no tax" model provides no less revenue to the provincial government than does the utility model, where the utility is a Crown corporation and pays no income taxes. The only differences between the private and utility models are that capital is given a high opportunity value by the private sector and a low opportunity value by a Crown corporation, and in federal and provincial income taxes.

Small-Scale Electrical Generation

There are many diesel plants in British Columbia, as sole service to remote communities, or providing peaking power. They range from about 1 000 to 7 000 kW. The total installed capacity has been tabulated as 122 000 kW. An economic analysis compares the energy cost of a diesel plant of 1 800 kW capacity and a simple geothermal plant of 1 500 kW capacity (Drawing

F-1, No. 4, shows the system). The diesel plant is a common off-the-shelf system; the energy produced is sensitive to the price of fuel. The geothermal plant underutilizes the available energy, but is inexpensive and fundamental. It discharges into the atmosphere. The geothermal energy cost is independent of any fuel price but is sensitive to the amount and cost of capital.

Again, the availability and the economics of the geothermal energy are dependent upon the outcome and the cost of exploration. The combined exploration and installation cost is estimated at three levels: $2 000 000, $4 000 000, and $9 000 000.

A diesel fuel price forecast for the period 1980 through year 2000 has been prepared by Canadian Resourcecon Ltd. Price in Canadian 1980 cents per liter is projected to increase from 17.99 to 39.76 during the 20-year period. The arithmetic average for the 20 years is 32.13¢ per liter. Other variables which are assumed for the purpose of the comparison are the discount rate, assumed at 3%, 6% and 12%; project life of 20 years; non-fuel operating, maintenance and administration expense of $100 000 per year for each plant, and capacity factors of 50% and 80%.

Levelized energy costs are tabulated in Table 3.

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Table 3 follows

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TABLE 3. Summary of Cost Comparisons of 1 800 kW Diesel and 1 500 kW Geothermal Generating Plants[1]

	Diesel Plant			Geothermal Plant		
				Low	Medium	High
Capital Cost (1980$ in millions)[2]	0.73			2.0	4.0	9.0
Energy Costs (1980¢/kWh)	In Year		Life Cycle Avg			
	1981	2000				
At 50% Capacity Factor and Discount Rate:						
3%	--	--	12.3	3.8	5.2	10.6
6%	--	--	12.4	4.4	6.4	13.5
12%	8.4	15.5	12.9	5.8	9.0	19.8
At 80% Capacity Factor and Discount Rate:						
3%	7.1	14.2	11.6	2.2	3.3	6.6
6%	--	--	11.7	2.7	4.0	8.4
12%	--	--	11.9	3.8	5.6	12.3

[1] Difference in capacities would be resolved in practice by suitability of geothermal plants to run at high capacity factors; this model presumes utility operation and includes no provision for federal and provincial taxes nor return on investment.

[2] Capital cost for diesel is calculated; for geothermal they are the sums of exploration and installation and are assumptions, based on experience, for purposes of these models.

Geothermal energy costs span a wide range, from 2.2¢/kWh to 19.8¢/kWh. The lowest cost diesel power ranges from 7.1¢/kWh in 1981 to 14.2¢/kWh in year 2000. The highest cost diesel energy ranges from 8.4¢/kWh to 15.5¢/kWh for the same years.

The economic model considered only cost of energy production, not income taxes or after-tax profits. The model presumes that the operator would be a Crown-owned utility or a natural resource company which generates and consumes its own electricity.

If geothermal energy can be discovered and developed at a level of 1 500 kW at a cost of somewhat less than $9 000 000 (assuming an appropriate discount rate), it will be clearly competitive with diesel fuel as a source. This is particularly true as time goes on, and it is particularly true in remote places where the transported cost of diesel fuel is higher than the forecasted price.

The chief economic disadvantage of geothermal energy for small capacity generating plants is the assumption of exploration risk.

An advantage of considering geothermal energy for small plants, and this advantage defies quantitative analysis, is that generally any geothermal system capable of electric production at the level of 1 500 kW is capable of far more production. The probabilities are that small-scale developments will be stepping stones toward local systems of 5 MW, 10 MW, or eventual connection into the province-wide system. A secondary advantage is that a geothermal reservoir in a remote location, utilized for small-scale generating plant, could be equally well utilized for direct space heating.

Economic Evaluation of Geothermal Space Heating

Approximately 50 communities, including some large cities, lie within areas which we have selected as possible geothermal resource areas. These are tabulated in Section 6 of this report (Table 6-18).

A geothermal space heating model was set up and analyzed in comparison to heating with the conventional fuels: natural gas, resistance electric, forced air electric, and light fuel oil. The engineering and economic parameters for space heating are well known from a large body of experience. The precision of the calculations far exceeds that of the assumptions on the geothermal system. Those assumptions are not facile, but necessary. In an actual case the variables would be known and measured quantities.

The model has the following characteristics:

1. An integrated community of 3 000 population, made up of 700 single family detached houses, 300 apartment units in blocks of 24 units, and 100 commercial establishments.
2. The climate is similar to that of Terrace, British Columbia, having 4 630 degree-days below 18°C.
3. The community is located within 5 kilometers of a geothermal resource.

4. The geothermal fluid has a temperature of 75°C, and has no troublesome chemical constitutents.

5. No exploration cost is charged to the project, and production wells are medium-yield, low cost wells, each delivering about 5 760 megajoules per hour, and each costing $1 600 000 to drill and complete.

6. The transmission system consists of a 5 kilometer pipeline from the wellhead to the distribution center, and the distribution system consists of 28 kilometers of pipeline serving individual buildings.

7. One sub-model supplies 100% of the required heat from 12 geothermal wells, and another supplies 70% of the required heat from 8 wells, with an auxiliary boiler which heats the fluid to 87°C for the peak heating loads.

The capital cost of the central supply, transmission, and distribution system is calculated as approximately $6.2-million for the 100% geothermal model and $5.3-million for the 70% geothermal model. The capital cost for the central system which delivers conventional fuels is assumed to be charged out to each customer in the price for the fuel, and is not calculated as a specific item.

Home heating plants using geothermal energy are basic. The principal system is a forced air "furnace" which blows air over coils and fins through which the geothermal water is circulated. For apartment blocks the system used is generally a baseboard convection system. The capital cost of both of these systems lies within the range of the capital cost for the various conventional systems.

The fuel price forecast developed by Canadian Resourcecon Ltd. was used to estimate the prices of conventional energy sources for the 20-year period, 1981 through the year 2000. When adjusted for efficiencies, this forecast suggests the following range of prices:

Expected Fuel Prices in 1980 Dollars per Gigajoule

Year	Light Fuel Oil	Electricity	Natural Gas
1980	6.38	8.34	2.96
1990	12.35	8.34	6.76
2000	15.03	8.35	8.16

Other owning and operating costs are considered: Process drive energy, such as pumps and fans, useful life of equipment, and discount rates of 6% and 12%.

Emphasis was placed on 55% of the geothermal heating load, which constitutes service to the 700 detached residences. The comparison of costs of heating with the various fuels is summarized in Table 6-16 from Section 6 of this report. Annual

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Table 6-16 follows

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costs, in 1980 constant dollars, are given on 5-year intervals for the 20-year period under consideration.

TABLE 6-16. Comparison of System Annual Owning and Operating Costs Based on the Price of Fuel in the Year

Heating System	Capital, Maintenance & Fixed Operating Costs 6% Discount Rate	1980	1985	1990	1995	2000
100% Geothermal	622,161	622,161	622,161	622,161	622,161	622,161
70% Geothermal	562,954[a]	562,954	562,954	562,954	562,954	562,954
Natural gas	287,003	561,903	732,303	914,803	981,703	1,045,503
Resistance electric	109,288	888,188	888,188	888,188	888,188	888,188
Forced air electric[b]	159,925	901,225	901,225	901,225	901,225	901,225
Fuel oil[b]	287,525	827,925	1,118,425	1,333,325	1,462,125	1,559,425
	12% Discount Rate					
100% Geothermal	945,859	945,859	945,859	945,859	945,859	945,859
70% Geothermal	868,064	868,064	868,064	868,064	868,064	868,064
Natural gas	448,159	723,059	893,459	1,075,959	1,142,859	1,206,659
Resistance electric	186,425	965,325	965,325	965,325	965,325	965,325
Forced air electric[b]	288,825	1,029,525	1,029,525	1,029,525	1,029,525	1,029,525
Fuel oil[b]	447,825	988,225	1,278,725	1,493,625	1,622,425	1,719,725

(a) Does not include costs of booster boiler fuel.

(b) Figures apply only to single detached accounts (700).

This model suggests that at the 6% discount rate geothermal will be competitive with the lowest cost conventional energy source, natural gas, by about 1985. At the 12% discount rate, geothermal heating will become competitive with natural gas by about 1990.

The constant cost of electric heating is a function of B.C. Hydro's announced intention to keep the retail price of electricity constant. If the geothermal heating were available, its economic advantage over electric heating is slender at the 12% discount rate, and residential customers might be deterred from choosing it by its high capital cost and unproven nature.

If geothermal heating fluid were free from impurities and suitable for use as domestic hot water, geothermal energy would have a remarkable long-term advantage over conventional energy sources.

Geothermal energy would be at a disadvantage, based on the economic model given, if the system involved retrofitting an existing community. In addition to alterations of heating plants within buildings, retrofitting would involve tearing up and repairing streets, sidewalks, and other utility systems. It is therefore more appropriately considered for a new community or an expansion of an existing community.

If the opportunity value of capital is such that a 12% discount rate is unrealistically low, the high capital cost for geothermal energy would put central heating systems at a disadvantage proportional to the increase in discount rate.

Geothermal heating would have a sharp economic advantage in communities where natural gas or system electric service is not available. The high delivered cost of fuel oil in remote places would contribute to any advantage which geothermal heating might have. In a one-industry resource community, where geothermal energy would be used for industrial purposes, a portion of the capital cost would be borne by the industry, and the service cost to residential customers would be reduced accordingly.

The geothermal developer might be a municipal district, an agency of the provincial or federal government, a utility company, an entrepreneur, or a resource company. There is no provision in the model for return on investment. Again, the major question, upon which any actual development would rest, is that someone must take the risk of exploration and proving of the actual geothermal resource.

Economics of Geothermal Heating for Aquaculture

Geothermal energy is ideally suited to fish hatcheries or fish farming because of the large quantities of total energy needed and the low threshold temperature permitted. Two hatchery models are described in Appendix H. One is a typical federal or provincial government hatchery which releases 1.5-million coho or 7-million chinook per year. The other is a rainbow trout farm, privately operated, which sells 1.6-million pan-sized trout annually. In climate conditions characteristic of southern British Columbia, each requires approximately the same total energy per year, or about 1½ times that required for the community of 3 000 population.

The maximum temperature required is 10°C to 14°C in the fish raising environment. Since low temperature resources are easier to find and develop than high temperature resources, it is an appropriate matching of technologies.

The cost of heating to maximum year-round levels using fuel oil would be prohibitive. In the case of the commercial trout farm operator, the cost of heating would be many times the wholesale price of his product.

The value of geothermal heat was calculated working backwards. A commercial trout farm operator would be willing to pay about 45¢ per kilogram of product in order to have year-round 14°C temperature. If operating and maintenance costs are negligible, the operator would amortise his well and transmission system at the rate of about $400 000 per year, or 3.3 mills per kilowatt hour (thermal) or 95¢ per gigajoule. At a discount rate of 12% and amortization period of 15 years, the operator would be willing to spend $2.7-million for geothermal energy development, provided the risk is low. This cost is well within the range of experience in drilling and completing low temperature geothermal wells.

Other Applications

No other specific economic models were worked out; however, the same features which make geothermal energy an attractive source for fish hatcheries apply to greenhouses. Geothermal energy is widely used for growing crops in Hungary, the United States, and Japan, in particular. Geothermal energy is also used for drying crops, drying clay products, refrigeration and space cooling by means of heat pumps, drying lumber, and providing hot water or steam to various industrial products. Geothermal energy can also be used for the production of fuel alcohols from agricultural and forest wastes. Various other aspects of direct geothermal energy use are reviewed in Appendix G.

EXPLORATION AND SOCIAL INSTITUTIONS

In a discussion of geothermal exploration, it helps if one thinks of exploration for oil, gas, or metal deposits. All of these are similar as to technology, the philosophy of the explorer, sensitivity to economic conditions, and sensitivity to social institutions.

Geothermal energy is unlike hydroelectric energy. The potential energy of a hydro site can be calculated from topographic maps, precipitation records and river gauge records.

The risk and unpredictability which accompany geothermal exploration are quantifiable only as broad industry-wide statistics. The success or failure of any individual program cannot be predicted, nor can the cost of a successful discovery.

With that caveat, we have estimated that a large, iterative program aimed at a discovery of a steam reservoir, capable of fitting in with the provincial electric system, might cost $4- to $20-million.

A program aimed at a 1- or 2-well local electric plant, and which uses every available short-cut to reduce costs, is estimated at $1- to $5-million. Such a program could not be started everywhere with any expectation of success; targets would have to be carefully picked.

The exploration cost for a low temperature reservoir capable of direct heating might be very little, e.g. drilling into an aquifer controlling a known hot spring, or it might be in excess of several million dollars, if justified by the proposed use.

In any case, some individual or group must be willing to take the risk prior to any promise of development.

The nature of the exploring institution defines its attitude on risk and influences its performance as an explorer. For example, an investor-owned or government-owned utility might be expected to conduct limited exploration programs for system electric targets, as they are perceived to meet the needs of the system. A utility could not be expected to scour the entire province, nor to explore for low temperature geothermal reservoirs.

Under certain economic conditions, resource companies could be expected to explore over a broad area, to prove up discoveries, to contribute capital toward development, to incidentally inventory subeconomic resources which would be useful at a future time, and to discover resources which would not be economic for electric conversion, but useful for direct utilization.

The milieu which makes up the private sector is composed of multinational oil and mining companies, independent oil and mining companies, publicly financed exploration companies, limited partnerships, and individuals. In each case their goal is to use their capital and their abilities for a gain. This group accomplishes thorough and efficient exploration because of competition, independent and contrary geologic thinking, intuition, a broad base of experience in many mineral commodities, and the presence of strong-willed individuals. This independent profit-oriented, exploration community is as highly developed and as aggressive in British Columbia as in any area of the world.

RATE OF PENETRATION OF GEOTHERMAL ENERGY SOURCES

The most speculative part of this report is to comply with the request to develop estimates of the rate of penetration of geothermal energy into the power source sector over the next several decades. System electric generating is the largest and most valuable use. The emphasis is placed on system electric.

The first speculative projection assumes that work will continue under existing legislation and procedures for the next 35 years. B.C. Hydro and Power Authority will be the only entity having an interest in developing geothermal power. The projection is shown in Drawing 7-3. The "low" rate of pene-

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Drawing 7-3 follows

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tration is none at all, connoting that the utility will be unsuccessful with current exploration at Meager Creek and will eventually abandon geothermal expectations. The "medium" rate of penetration assumes development of 100 MW, perhaps at the Meager Creek field or perhaps at another field. The "high" rate of penetration assumes incrementation of a geothermal field to 400 MW capacity by year 1995 and continued operation at that level. The "very high" rate of penetration assumes that a second field would be brought in a decade later, and total geothermal capacity in the province would be 800 MW.

We would guess that 2 or 3 local electric plants might be developed during the next 35 years. We speculate that 2 to 5 direct utilization projects may evolve and grow. These would probably be carried out from known thermal springs by private entrepreneurs, prompted by increases in costs of conventional fuels, and undertaken initially as much for the purpose of saving costs of an ongoing activity as for making a direct profit from energy sales.

Drawing 7-4 offers three speculations on rate of penetration

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Drawing 7-4 follows

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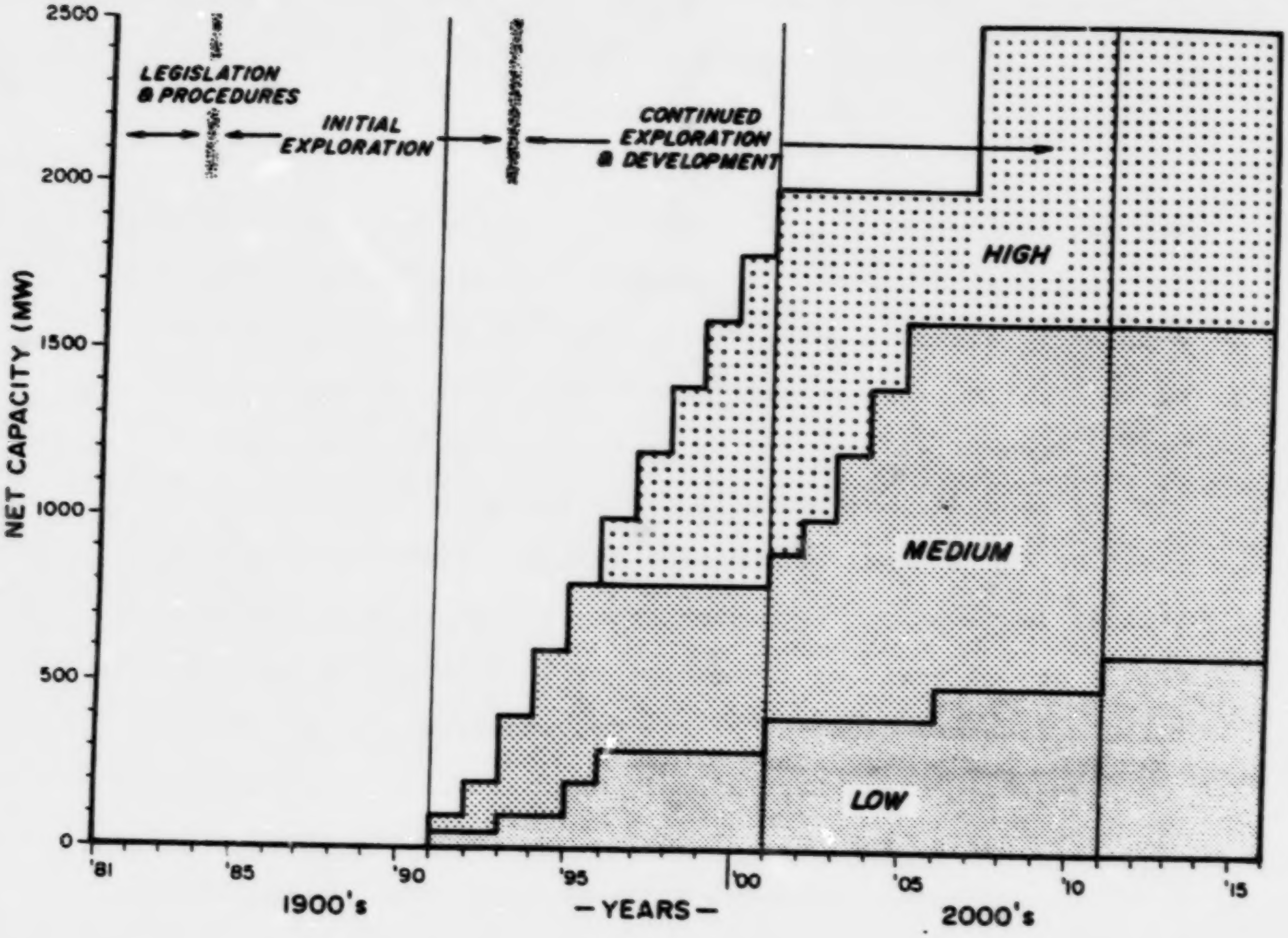
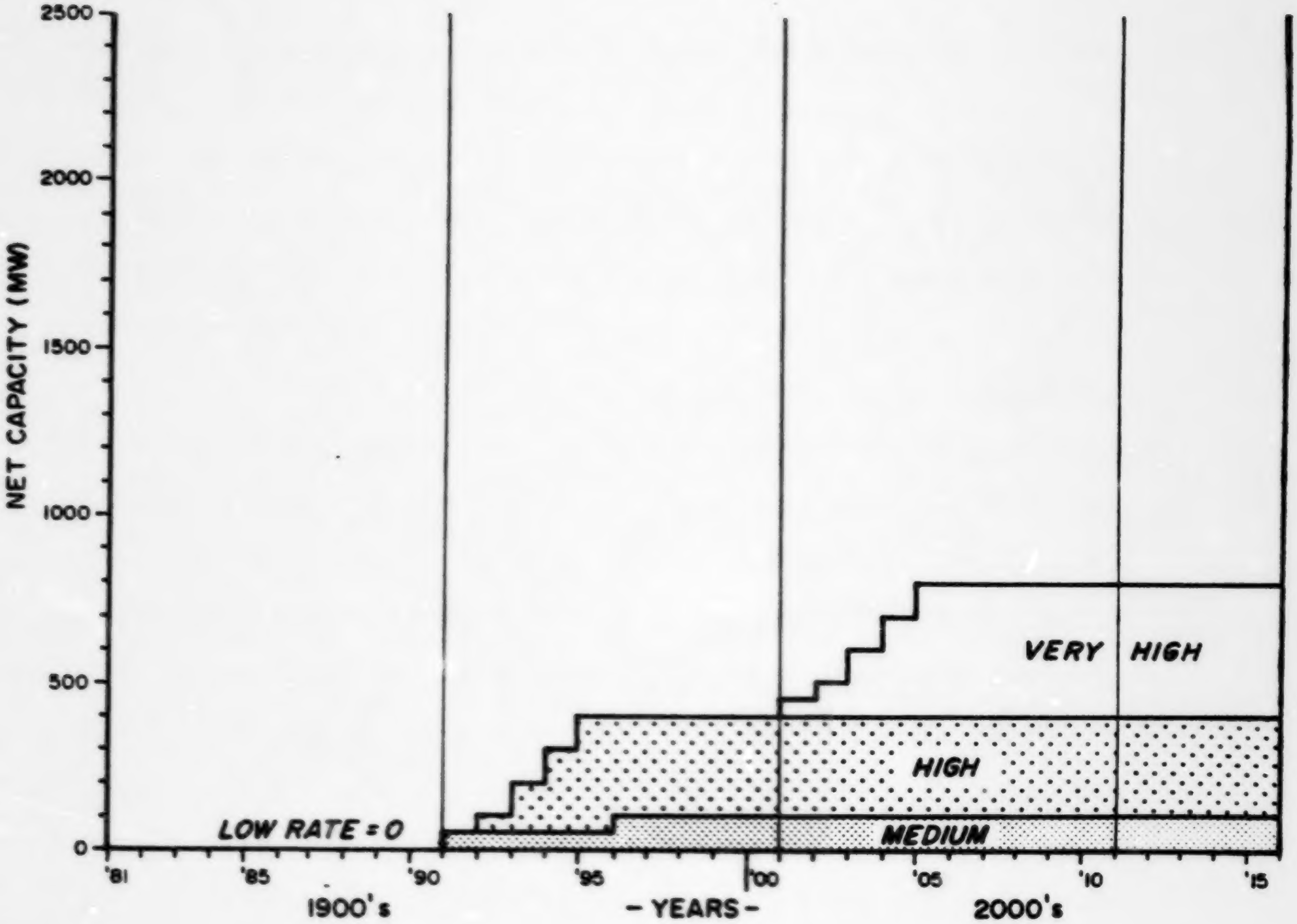


DRAWING 7-4

THREE SPECULATIONS ON RATE OF PENETRATION OF GEOTHERMAL ENERGY FOR SYSTEM ELECTRIC POWER, 1981-2015, UNDER LEGISLATION ENCOURAGING PRIVATE SECTOR



DRAWING 7-3

FOUR SPECULATIONS ON RATE OF PENETRATION OF GEOTHERMAL ENERGY FOR SYSTEM ELECTRIC POWER, 1981-2015, B.C. GEOTHERMAL RESOURCES ACT (1973) under conditions which would permit and encourage private sector leasing, exploration, development, and marketing of electricity. Public sector development is included, but not differentiated. We speculate that the "low" rate of penetration will start out with the installation of 100 MW of generating capacity by 1993 and will increment in 100 MW steps, reaching 400 megawatts by 2001 and 600 megawatts by 2011.

The highest rate of penetration presumes excellent marketing opportunities to utilize a correspondingly high discovery rate. Capacity grows to 2 500 MW in year 2006, incrementing at a rate of 200 MW per year from 1993 to 2001, during the period of greatest growth. No single geothermal project in the world has grown at this rate yet, nor has the geothermal generating capacity of any country reached the level of 2 500 MW. However, there is no inherent reason why such rapid development will not take place in the future in one or more projects in a country, state or province which has a good resource base. The "medium" rate of penetration assumes that two fields will each be developed to about the magnitude of the present Geysers installation in California.

We believe that the competitive exploration milieu will seek large, high-value, system-electric reservoirs, and they will inevitably discover and develop low-grade and smaller reservoirs as well. Momentum and skills will propagate toward specific use of geothermal resources near thermal demand. We expect that by year 2015, more than a dozen local electric and direct use schemes will be in various stages of design, construction, production or expansion.

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